Entergy

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June 20, 2016

Via Hand Delivery
Ms. Lora W. Johnson, CMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief
CNO Docket NO.: UD-16-____

Dear Ms. Johnson:

Please find enclosed for your further handling an original and three copies of the Public Application of Entergy New Orleans, Inc. ("ENO") for Approval to Construct New Orleans Power Station and Request for Cost Recovery and for Timely Relief. This filing includes the Direct Testimony and Exhibits of Charles L. Rice, Jr., Orlando Todd, Seth E. Cureington, Jonathan E. Long, Charles W. Long Shauna Lovorn-Marriage, and Robert A. Breedlove. Please file an original and two copies into the record in the above referenced matter, and return a date stamped copy to our courier.

In connection with the Company's filing, a Confidential Version of the above-described documents bearing the designation "Highly Sensitive Protected Materials" are being provided to the Council's Advisors pursuant to the terms and conditions of the Official Protective Order adopted in Council Resolution R-07-432. Portions of the information included in the filing consist of competitively sensitive cost and market information, the disclosure of which may create an artificial target for suppliers in an otherwise competitive wholesale market. In addition, portions of the filing contain highly sensitive information of third parties, to which an obligation of confidentiality is owed. The disclosure of the information contained herein to suppliers to ENO would subject not only the Company, but also its customers, to a substantial risk of harm. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

Thank you for your assistance with this matter.

Sincerely,

Timothy S. Cragin

Enclosure

cc: Honorable Stacy S. Head (*via electronic mail and U.S. Mail*)
Honorable Jason Rogers Williams (*via electronic mail and U.S. Mail*)
Honorable Susan G. Guidry (*via electronic mail and U.S. Mail*)
Honorable LaToya Cantrell (*via electronic mail and U.S. Mail*)
Honorable Nadine M. Ramsey (*via electronic mail and U.S. Mail*)
Honorable Jared C. Brossett (*via electronic mail and U.S. Mail*)
Honorable James Austin Gray, II (*via electronic mail and U.S. Mail*)
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Rebecca Dietz (*via electronic mail and U.S. Mail*)
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Errol Smith, CPA (*via electronic mail and UPS*)

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	)))))	**DOCKET NO. UD-16-____**

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF

Entergy New Orleans, Inc. ("ENO" or the "Company") respectfully submits this Application to the Council of the City of New Orleans ("Council"), which seeks, among other requests, authorization to proceed with constructing the New Orleans Power Station ("NOPS" or the "Project"), an advanced combustion turbine ("CT") in New Orleans,[1] Louisiana. As detailed below and in the accompanying Direct Testimony, NOPS will be a 226 megawatt ("MW")[2] CT located at ENO's Michoud facility in New Orleans East. In addition to a finding that the construction of NOPS is in the public interest, the Company also requests approvals relating to appropriate cost recovery, a construction monitoring plan, and a procedural schedule to permit a Council decision on this Application by January 2017. In support of these requests, the Company represents the following:

[1] Nominal size refers to the general size of the unit. As discussed later in my testimony, actual output of a unit depends on a number of factors that vary from unit to unit and site to site.

[2] As discussed more fully by Company witness Mr. Jonathan E Long, NOPS, in a new and clean condition, would be expected to generate approximately 226 MW at Summer conditions of 97° F and 59% relative humidity.

INTRODUCTION

I.

ENO is an electric and gas utility organized and operating under the laws of the State of Louisiana, with its general office and principal place of business at 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112. The Company is engaged in the manufacture, production, transmission, distribution, and sale of electricity to residential, commercial, industrial, and governmental consumers throughout Orleans Parish. As of December 31, 2015, ENO furnished electric service to approximately 196,711 retail electric customers in Orleans Parish. ENO is also engaged in the provision of natural gas service throughout New Orleans and serves approximately 105,501 retail gas customers.

II.

As discussed herein and in the accompanying supporting testimony, the Company has a long-term supply need for peaking/reserve capacity. As discussed more fully below, and in the accompanying direct testimony, generating resources that employ CT technology such as NOPS are technologically and economically suited both for peaking and reserve roles, which is consistent with ENO's load shape.

III.

The recent deactivation of Michoud Units 2 and 3, which were economic decisions based on maintenance and operational issues, resulted in the loss of approximately 781 MW of local capacity (which is approximately a significant portion of ENO's 2016 forecasted non-coincident peak load). As a result, ENO has a need for overall capacity as well as a need for local peaking and reserve capacity resources. While the acquisition of Power Block 1 of the Union Power Station ("Power Block 1") helped to offset a substantial portion of ENO's overall capacity needs (including baseload and load-following need), the Company has a remaining overall long-term capacity need of approximately 123 MW in 2016 and up to 205 MW by 2030. Moreover, current projections show that ENO has an existing long-term need for approximately 288 MW of peaking and 118 MW of reserve capacity resources (Total: 406 MW) in 2016, which need is expected to persist throughout the planning horizon absent the addition of new resources capable of meeting those needs.

IV.

ENO's need comes at a time when the capacity market in MISO South is expected to tighten, reaching equilibrium (the point at which supply and demand meet) by 2022. Thus, deferring construction of a new resource comes with considerable risk considering the long lead-time necessary to gain regulatory approval of, plan, and construct new resources, potential cost premiums for parts and equipment as other utilities are simultaneously shifting to modern, gas-fired resources, and expected sharply higher and more volatile capacity prices during that time frame.

V.

While the Company continues to seek opportunities to offset some of its capacity needs with energy efficiency and demand-side management ("DSM") programs, as well as adding renewable resources to its generation portfolio, such resources are not alternatives to NOPS and cannot fill the long-term peaking/reserve capacity deficit in a cost-effective manner during the long-term planning period. Neither can the Company rely on the MISO capacity market for its long-term capacity needs. Further, as discussed more fully below, the Company's long-term planning indicates a need for a local resource that can support local reliability, reduce reliance on transmission and resources external to Orleans Parish, and facilitate storm restoration.

VI.

The Company also requests that the Council issue the approvals requested herein no later than January 31, 2017. This procedural schedule will allow the Company to issue timely notice to proceed ("NTP") to the engineering, procurement, and construction ("EPC") services contractor selected for the Project. As discussed in the Direct Testimony of Mr. Jonathan Long, the estimated cost to construct NOPS assumes that the Company is able to issue NTP no later than [redacted], following receipt of acceptable approvals from the Council, which issuance is expected to result in commercial operation of NOPS in October 2019.

VII.

With this Joint Application, the Company is submitting the Direct Testimonies of Charles L. Rice, Orlando Todd, Seth E. Cureington, Jonathan E. Long, Charles W. Long, Shauna Lovorn-Marriage, and Robert A. Breedlove. The purpose of the testimony of each witness is as follows:

- Charles L. Rice – Mr. Rice, President and Chief Executive Officer of ENO, provides an overview of the Project and the Application. He also introduces the testimony of the other witnesses supporting the Joint Application.
- Orlando Todd – Mr. Todd is the Finance Director for ENO. Mr. Todd provides the estimated first-year revenue requirement associated with the Project. He also describes the proposal to recover, through the applicable fuel adjustment clause ("FAC"), the variable costs associated with the Long-Term Service Agreement ("LTSA") that ENO will enter into in connection with certain major maintenance activities for NOPS. In addition, Mr. Todd explains the proposed rate recovery plan and the importance of timely recovery with respect to the costs related to the

Project.

- Jonathan E. Long – Mr. Jonathan Long is the Vice President, Project Management for Entergy Services, Inc. ("ESI")[3]. He provides an overview of the Project, explains how the cost estimate associated with the Project was developed, and provides the current cost estimate and schedule for the Project. He also describes the management approach that the Company intends to employ and the process used to select the EPC contractor for the Project. He also discusses the risk mitigation measures put in place to control Project risk. Finally, Mr. Jonathan Long discusses the status of the required permits/approvals for the Project.
- Seth E. Cureington – Mr. Cureington is the Manager, Resource Planning and Market Operations for ENO. Mr. Cureington discusses the Company's long-term resource planning process, the Company's long-term resource needs, including a need for local peaking and reserve capacity resources, and how the Project addresses those needs. He also describes the supply conditions in MISO South are expected to tighten by planning year 2022. Finally, Mr. Cureington discusses the site selection for the Project.
- Charles W. Long – Mr. Charles Long is the Director of Transmission Planning for ESI. He describes, from the transmission perspective, the unique characteristics of the Downstream of Gypsy ("DSG")[4] region and how the construction of NOPS will have the effect of avoiding/delaying projects that would otherwise be

[3] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), ELL, Entergy Mississippi, Inc. ("EMI"), ENO, and Entergy Texas, Inc. ("ETI").

[4] DSG encompasses ENO's entire service footprint and is the transmission planning region located to the south of the Lake Pontchartrain, up to the Mississippi state border, and bounded by the Gulf of Mexico to the south.

necessary to maintain reliability. Mr. Long also describes the transmission-related reliability benefits associated with constructing NOPS and the process MISO uses to identify transmission upgrades that may be necessary for the integration of NOPS into the electric grid.

- Shauna Lovorn-Marriage – Ms. Lovorn-Marriage is the Director, Regulatory Filings for ESI. Ms. Lovorn-Marriage discusses the regulatory and ratemaking issues that will need to be resolved in order for the Company to initiate and successfully complete the Project at the lowest reasonable cost. Specifically, she (1) proposes a regulatory approval plan that is in the public interest; (2) sets forth approvals required by the Company before committing significant capital to build the Project; (3) discusses the Company's compliance with applicable Council Orders; (4) sets forth the specific requested findings concerning the public interest; (5) discusses why the approval of the Project is in the public interest; and (6) discusses the proposed to monitor construction progress.
- Robert A. Breedlove – Mr. Breedlove is the Director of Plant Support in Fossil Operations for ESI. Mr. Breedlove provides a general description of CT technology, including how that technology has developed. He also describes the estimated operation and maintenance ("O&M) costs for the Project. Finally, he describes the Company's plan to manage major maintenance on the Project's major equipment.

This Application and the supporting testimony include the specific data that the Company relied upon in making the decision to construct NOPS, an estimate of the costs to construct NOPS, ENO's estimated first year, non-fuel revenue requirement associated with NOPS, the estimated in-service date, and the construction schedule and milestones.

OVERVIEW OF RESOURCE

VIII.

As described in more detail by Mr. Jonathan Long in his Direct Testimony, the Company proposes to construct NOPS, which will provide approximately 226 MW (nominal) of summer generating capacity, consisting of one Mitsubishi Hitachi Power Systems America, Inc. ("MHPSA") 501 GAC CT. The plant will be located in New Orleans, Louisiana adjacent to the existing Michoud facility. The base elevation of the unit will be 3.5' above sea level. Allowance for a flooding event similar to Hurricane Katrina was included in the design of the power block elevation. The unit will be protected by levees constructed along the Intracoastal Waterway, and the Lake Borgne surge barrier that were constructed/improved after Hurricane Katrina.

IX.

As Mr. Jonathan Long discusses in his Direct Testimony, the current estimated cost to construct NOPS is $216 million, which reflects the use of a fixed-price, fixed-duration form of EPC contract, subject to certain defined possible adjustments. The EPC contract accounts for a significant portion of the overall estimated cost of the Project. Other components included in the overall Project cost estimate are an allowance for funds used during construction ("AFUDC"), transmission interconnection to the switchyard, project contingency, internal construction management, indirect loaders, insurance coverage, expenses related to seeking Council certification, and other non-EPC costs. Mr. Charles Long describes the MISO interconnection study process in his Direct Testimony, which is not expected, but could identify transmission interconnection costs that have not been included in the Project estimate.

X.

The estimated costs of operating and maintaining NOPS are detailed in the Direct Testimony of Mr. Breedlove, and these costs are reflected in the estimated first-year non-fuel revenue requirement set forth in the Direct Testimony of Mr. Todd.

XI.

As discussed in the Direct Testimony of Mr. Rice, the construction of the Project is expected to have a positive impact on the economies of the State of Louisiana and Orleans Parish. Loren C. Scott & Associates, Inc. conducted a study and concluded that the construction and operation of NOPS will produce significant economic benefits – totaling hundreds of millions of dollars – in terms of new business sales, household earnings, and jobs in both the State and Parish economies. Benefits result not only from one-time capital expenditures, but also from ongoing operational expenditures that will continue to accrue to the benefit of residents in Orleans Parish as long as NOPS is in operation.

FACILITY DESCRIPTION

XII.

In accordance with the Council's directive in Resolution R-15-524, which directed the Company to use "reasonable diligent efforts" to pursue development of a peaking resource in Orleans Parish following termination of the Entergy System Agreement, the site selection process involved identification of potential locations for the development of new generation in Orleans Parish. Considerations included factors related to fuel supply, transmission, existing infrastructure, site suitability, and environmental regulations. As is detailed in the Direct Testimony of Seth Cureington, two potential sites were evaluated for new unit suitability: A.B. Paterson and Michoud. A.B. Paterson was eliminated due to limited fuel and other infrastructure. Michoud is located closer to three major gas pipelines, and it has existing office building infrastructure as well as available bays in the high-voltage switchyard. In addition, the Michoud substation is more strongly interconnected to the DSG load pocket via multiple lines at both 230 kV and 115 kV voltages, which enables a resource at the Michoud site to provide more support to reliability in DSG, and accordingly in New Orleans, versus a resource interconnected at the A.B. Paterson site.

XIII.

As Company witness Jonathan E. Long explains, NOPS will use newer, cleaner, and more efficient technology than the recently deactivated units at the Michoud site. This means that NOPS will produce significantly lower emission levels than the recently deactivated units.

Moreover, although ENO does not believe any material impacts resulted from groundwater usage by the deactivated Michoud units, the Council should be aware that NOPS will result in a substantial decrease in the capacity for groundwater usage when compared to the recently deactivated units. Considering the absolute maximum possible groundwater usage for NOPS, there is expected to be a reduction of 90% in comparison to the deactivated Michoud units. Moreover, considering the maximum expected groundwater usage for NOPS, there is expected to be a reduction of approximately 99%.

PROJECT EXECUTION AND MANAGEMENT

XIV.

As explained in the Direct Testimony of Mr. Jonathan Long, the Company has chosen a single-source EPC approach for the Project to ensure that the resources necessary to execute this substantial undertaking are brought to bear in a timely and cost-effective manner. The Company negotiated a fixed-price,[5] fixed-schedule duration form of EPC contract with Chicago Bridge & Iron, Inc. ("CB&I") that reflects a detailed scope of work.

XV.

CB&I was the EPC contractor for Ninemile Unit 6 ("Ninemile 6"),[6] and the Company followed the same contracting approach for NOPS that resulted in the successful, timely, and under-budget completion of Ninemile 6. The EPC contract was awarded to CB&I as a result of a competitive procurement process and its knowledge of the Company's processes gleaned from Ninemile 6, commercially reasonable pricing, and the competitiveness of CB&I's costs with market alternatives.

XVI.

Under the fixed-price EPC contract structure, CB&I will act as an independent contractor with respect to the engineering, procurement, and construction services defined in the contract's scope of work. CB&I also will procure the combustion turbines and balance of plant equipment from the original equipment manufacturers ("OEMs"). CB&I's procurement of this equipment will allow it full coordination and scheduling of the OEMs in order to meet the fixed schedule provided in the contract.

XVII.

The EPC contract requires substantial completion of the Project 31 months after NTP is issued by the Company, provided that NTP is issued in or before [redacted] If final non-appealable Council approvals are not obtained by January 31, 2017, such that NTP cannot

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5 As Mr. Jonathan Long explains, although the EPC agreement with CB&I is a fixed-price form of contract, there are elements of the pricing that are not fixed.

6 It should be noted that ENO purchases 20% of the capacity and energy of Ninemile 6 through a purchase power agreement ("PPA") with ELL.

be issued by [redacted], the EPC contract price is subject to escalation under the terms of the agreement. If NTP is issued after [redacted], the full price of the EPC contract will be subject to renegotiation instead of contractual escalation.

XVIII.

As discussed by Mr. Jonathan Long in his Direct Testimony, the Company does not have the in-house capability to provide all of the required EPC services for the Project. The use of an EPC contractor like CB&I, which can perform all of these functions under a single contract, is cost-effective and common within the industry for such projects. The Project will be managed and monitored by the Company through a Project Team, led by a Project Director, with oversight from an Executive Steering Committee ("ESC"). The ESC will provide oversight and strategic direction for the Project and will monitor and provide direction relating to Project performance, key risks, and value drivers that may affect the Project risk profile.

XIX.

As a part of the EPC Agreement, ENO will require CB&I to provide opportunities to small and disadvantaged businesses for participation in any subcontracts and purchase orders let in the performance of its obligations as the EPC contractor. The Company will require CB&I to develop and maintain a list of Diverse Subcontractors and Suppliers that will be supplied to ENO on a quarterly basis. Minority-owned businesses, women-owned businesses, veteran-owned businesses, and disabled-veteran-owned businesses, among others, are included within the meaning of "diverse subcontractors and suppliers." CB&I will be required to submit a plan for utilizing diverse subcontractors and suppliers to ensure such participation in the construction of NOPS.

THE PLANNING PROCESS AND RESOURCE NEEDS

XX.

Mr. Cureington describes the Company's long-term resource planning process in his Direct Testimony. ENO's strategy to address resource needs is currently being planned on a stand-alone basis, as its participation in the Entergy System Agreement ("ESA"), along with all of the other remaining EOCs that are participating in the ESA, will terminate on August 31, 2016. Accordingly, ENO's long-term resource needs reflect a post-ESA planning environment. Importantly, as discussed by Company witness Ms. Shauna Lovorn-Marriage, the conditions upon which the Council approved early termination of the ESA included a commitment by the Company to pursue a new generating resource to be located in the Company's service area (*i.e.*, Orleans Parish, Louisiana).

XXI.

The Company's long-term resource planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk. In support of that objective the Company must maintain a portfolio of generation resources deliverable to load that includes an appropriate amount and types of capacity. With respect to the amount of capacity, the Company must maintain sufficient generating capacity to meet its peak load plus a planning reserve margin ("PRM"), for which the Company has established a target of 12%. With regard to the types of capacity, the Company seeks to add modern, reliable and cost-effective generating technologies consistent with its load shape. Importantly, these objectives must be considered both individually and collectively in determining an appropriate portfolio design that can achieve planning objectives.

XXII.

Consistent with the long-term planning objectives identified above, in Docket No. UD-08-02, ENO was ordered to conduct an Integrated Resource Plan ("IRP") process, which gave stakeholders an opportunity to provide feedback regarding ENO's long-term planning assumptions. ENO held its first 2015 IRP technical conference required by Resolution No. R-14-224 ("IRP Resolution"), the Milestone 1 technical conference, on June 23, 2014. Thereafter, after a nearly two-year process including a series of technical conferences and a draft IRP, ENO filed its Final 2015 IRP on February 1, 2016. The IRP process identified an overall long-term need for capacity as well as a need for long-term peaking and reserve resources. In the IRP, the Company conducted the DSM Potential Study, Generation Technology Assessment, and Portfolio Evaluation, which thoroughly evaluated of a range of viable supply and demand-side alternatives capable of meeting those needs. The results of the Final 2015 IRP support the conclusion that a CT resource is the lowest reasonable cost resource addition capable of meeting the Company's overall capacity needs (including the target PRM).

XXIII.

Even after accounting for existing and recently acquired supply and demand-side resources, and including the effect of current energy efficiency and DSM programs, the Company continues to have a need for additional long-term capacity, including a need for peaking and reserve capacity. The Company projects an overall need for approximately 134 MW of capacity by 2020 and up to 205 MW by 2030. The Company projects the need for approximately 377 MW of peaking and reserve resources by 2020 that persists throughout the planning horizon. The increase in the Company's long-term need for capacity is driven primarily by the deactivation of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational issues. Power Block 1 helped to offset these deactivations.

XXIV.

CT resources, such as NOPS, are technologically suited for serving peaking and reserve roles. As discussed by Company witness Jonathan Long, NOPS is a modern CT unit capable of being started quickly and ramped to full load within minutes. This capability will support local area reliability and facilitate distributed energy resources such as solar photovoltaic ("PV"), which has increased significantly in the Company's service area. Further, CT technology is economically suited to serve in these roles across a range of assumptions regarding key uncertainties (*e.g.*, fuel prices, emissions cost, *etc*.). CT resources such as NOPS support the Company's planning objectives. Mr. Cureington also describes selection process for the MHPSA 501 GAC CT, explaining that out of seven different CT technologies, the turbine selected for NOPS provides the highest capacity rating and lowest total supply cost of all seven technologies.

XXV.

As Mr. Cureington discusses in his Direct Testimony, renewable resources such as wind and solar PV are intermittent as they rely on the wind and sun to produce energy, thus limiting the ability to rely on them to meet customer demand and their ability to be counted on to meet peak demands. As a result, renewables must be supported by dispatchable resources such as CTs to ensure sufficient resources are available to ramp-up and produce replacement energy when the wind is either not blowing or blowing less than projected, and similarly when cloud cover or unexpected weather limits the output of solar PV. Finally, because wind and solar are intermittent, these resources would not eliminate the need for quick-start and fast ramping dispatchable resources such as NOPS. It should also be noted that because they are intermittent, the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs. Thus, even if intermittent resources could meet ENO's peaking and reserve needs (which they cannot), the Company would need to acquire/construct significantly more of these resources than its capacity need dictates due to their lower capacity factor.

XXVI.

Intermittent resources have a place in ENO's supply portfolio. To the extent that those resources can provide cost effective sources of energy, they will benefit customers. Indeed, ENO is undertaking an RFP to determine whether there are cost-effective renewable resources available.[7] However, without cost-effective storage, which does not exist at this time, it is not possible to utilize intermittent resources to meet ENO's capacity reserve needs and, in turn, ensure reliable service to customers.

XXVII.

As Mr. Cureington discusses, no achievable DSM resources are available to meet the Company's peak capacity needs. Indeed, the present load forecasts have taken into account all existing entergy efficiency and demand side management in ENO's portfolio and they do not offset the need for NOPS. Moreover, additional DSM and energy efficiency ("EE") programs are costly to administer and results therefrom continue to be uncertain. The Company engaged ICF International ("ICF") to conduct an analysis of the long-term DSM potential achievable in

[7] On May 6, 2016 ESI issued a draft request for proposals for renewable generation resources. The RFP will facilitate a market test of the extent, and cost of, renewable resources available to provide benefits in excess of cost to the Company's customers. More information on the Draft RFP can be found on the ESI RFP Website located at: https://spofossil.entergy.com/ENTRFP/SEND/2016ENOIRenewableRFP/Index.htm.

New Orleans. ICF concluded that the achievable amount of DSM in New Orleans constitutes only approximately 13% of ENO's need for peaking and reserve capacity by 2020.

XXVIII.

It is also important to note that market equilibrium (the point at which supply, including third-party resources, and demand, including appropriate planning reserves, are in balance) approaches, customers will be exposed to an increased risk of significantly higher costs for capacity due to the labor and equipment premiums and long lead times that would be required to build new resources to address the shortage. MISO has projected equilibrium in MISO South in 2022. As discussed by Mr. Cureington, the recent 20-fold increase for capacity in MISO's capacity auction for MISO Local Resource Zones ("LRZ") 2 through 3 and 5 through 7 for the prior 2015/2016 Planning provides a concrete example of the effect on capacity prices as available capacity in the market begins to tighten. Accordingly, it is unreasonable for ENO to rely on the market for capacity, exposing customers to such price risks.

TRANSMISSION

XXIX.

As Mr. Charles Long explains in his Direct Testimony, the City of New Orleans is located in the DSG load pocket, which has unique geographical limitations (*i.e.*, it is largely surrounded by water) and contains highly concentrated electrical loads. The geography of the region limits the transmission facilities that serve the region, and accordingly, New Orleans. These circumstances also make the region reliant upon local generation to maintain reliable service. Further, as described by Mr. Cureington, following the recent deactivation of Michoud Units 2 and 3, the four units that ENO currently depends on for reliability in DSG are all located outside of Orleans Parish.

XXX.

Mr. Charles Long discusses the fact that NOPS has been included in ENO's plan to ensure long-term reliability beginning in October 2019. If the unit is not constructed, the Company would be required to re-assess its plan for compliance with North American Electric Reliability Corporation ("NERC") standards and alternative plans involving transmission upgrades to avoid reliability challenges over the ten-year planning horizon would be necessary. In other words, the exclusion of NOPS would likely involve the construction of multiple new transmission facilities in the greater New Orleans area, each of which would be difficult and costly to construct given the limited land availability and environmental challenges associated with transmission line construction in that region. Mr. Charles Long also states that a smaller resource would not completely address the reliability concerns. Virtually the entire 226MW of capacity that is planned for NOPS is needed to completely mitigate the reliability issues described above for the ten-year planning horizon or additional mitigation measures would be required.

XXXI.

Mr. Charles Long describes in his Direct Testimony that when generating capacity is added to the electric grid, it produces the most transmission-related benefits when located in proximity to the load that it will serve. Locating the proposed NOPS generator at the Michoud site will produce the following benefits:

- Increased load-serving capability in the New Orleans area, which is supportive to economic growth;
- Improved ability to serve existing load reliably by reducing the region's dependence on already strained transmission facilities;

- Increased operational flexibility such that necessary maintenance activities for generation and transmission facilities in the area could be planned more efficiently without incurring operational risk during planned outages;
- Increased reactive power, which would improve stability in the DSG region and would thus avoid potential voltage instability and increasing system efficiency by providing reactive power margins to existing customers and supporting future industrial growth;
- Increased storm restoration benefits, which would help the Company to restore service to customers in a timely manner following a major storm event.

XXXII.

Significantly, Mr. Charles Long explains that NOPS also adds a local source of active or "real" power in the DSG load pocket with the ability to start quickly. This will aid in shortening the time to restore service to customers after large scale events such as hurricanes or other natural disasters. For example, if the transmission system experiences extensive damage during a hurricane, which is often the case in the New Orleans area, the ability to import power across the transmission lines may be impaired for many days due to transmission system damages. In such a scenario, local generation units make it possible to locally supply power through a smaller number of relatively short transmission lines which can be repaired more quickly. A unit like the proposed NOPS provides a "starting point" for restoration and could potentially allow restorations to occur more quickly than would be possible relying solely on transmission facilities. A local generator, such as NOPS, will also greatly aid in maintaining the integrity of the electric system in the event that a storm severs the electric grid in a manner that creates an electrical island.

XXXIII.

In his Direct Testimony, Mr. Charles Long discusses the three different categories of transmission upgrades that may be required for NOPS. First, transmission upgrades will be required to physically connect the generator to the electrical system, which upgrades typically consist of transmission or distribution-voltage lines or cables necessary to connect the generator step-up transformer with the interconnection substation, circuit breakers, and associated switches and any substation yard work. As Mr. Charles Long explains, a total of $2.3 million in transmission upgrades have been identified as interconnection costs for NOPS. Second, transmission upgrades may be identified by the Midcontinent Independent System Operator, Inc. ("MISO") that are necessary to designate NOPS as a Network Resource (*i.e.*, for the resource to be granted Network Resource Interconnection Service). MISO has not yet completed its study of this issue, which process is discussed by Mr. Charles Long, and so the cost of any upgrades that are identified has not been estimated by the Company. Third, transmission upgrades may be necessary to mitigate any reliability issues under the NERC Reliability Standards and/or Planning Criteria that may result from the interconnection of NOPS. As Mr. Charles Long explains, the Company will not be able to identify any such upgrades until the Company signs the Generation Interconnection Agreement for NOPS and the generating plant is included in the loadflow models that are used by the Company to perform their annual long-term reliability assessment. However, the Company performed its reliability analysis in 2016 with NOPS included in the base case models representing the electric system. The reliability analysis was performed to assess the Company's ability to comply with NERC Reliability Standard TPL-001-4. The 2016 assessment did not identify any reliability violations associated with a new NOPS for any period within the ten year planning horizon, thus, the Company does not expect additional upgrades to be identified for the foreseeable future.

COMPLIANCE WITH APPLICABLE COUNCIL RULES AND ORDERS

XXXIV.

For the reasons discussed previously and in detail in the accompanying testimony, NOPS is in the public interest, and is therefore prudent, and should be approved by the Council. As discussed above, the Project will add a modern source of CT capacity to the Company's generating resource portfolio that can be used in either a reserve or peaking role as necessary or appropriate, and will contribute to meeting the Company's long-term supply needs. Moreover, NOPS will support system reliability by adding necessary capacity within the supply-constrained DSG region at a cost that is favorable when compared to other available options.

REGULATORY APPROVALS

XXXV.

As detailed in the Direct Testimony of Ms. Shauna Lovorn-Marriage, this proceeding presents possibly the first time in more than thirty years that the Company has asked the Council to approve the construction of a generating unit by ENO. The Company proposes a process whereby the Council would issue a decision, supported by the evidence and sound regulatory principles, that the construction of the Project is in the public interest and therefore prudent. As part of this decision, the Council would approve an In-Service Cost Recovery Plan, which is discussed by Mr. Orlando Todd. In the past, the Council has allowed timely recovery of the costs associated with new resources obtained for the benefit of ENO's customers, such as Union Power Block 1 and the PPA with respect to Ninemile 6. Such rate treatment provides an incentive for ENO to continue to undertake large investments or obligations in order to secure benefits for its customers.

ENO expects the Project to commence commercial operation in the second half of 2019. At that time, the Company expects the Combined Rate Case described in Paragraph 8 of the Algiers Transaction Agreement in Principle approved in Council Resolution R-15-194, dated May 14, 2015, to be complete and all of ENO's customers to be subject to a single set of Council-approved base rates and riders. As a result of that proceeding, the Company further expects that the recovery of the capacity costs associated with the Ninemile 6 Unit and associated with Union Power Station Power Block 1 will be realigned from the Purchased Power and Capacity Acquisition Cost Recovery Rider ("PPCACR Rider") to base rates. Finally, the Company expects that ENO will be subject to a formula rate plan ("FRP") following the Combined Rate Case. These are the principal regulatory assumptions that are the context for ENO's proposed cost recovery plan.

XXXVI.

ENO proposes that the non-fuel revenue requirement associated with the Project initially be recovered contemporaneous with commercial operation of the Project through the PPCACR Rider, which would be modified for such purpose, or a similar exact cost recovery rider. This rider would use the Company's weighted average cost of capital ("WACC"), including its actual capital structure, at the time the Project commences commercial operation to determine the return on the Company's investment in the Project, and the return on equity resulting from the Combined Rate Case. These costs would be recovered from all of the Company's customers, including Algiers customers, which today do not pay charges pursuant to the PPCACR Rider. In the next FRP proceeding commencing in 2020, the Project's non-fuel revenue requirement would be realigned so as to be recovered through the FRP Rate Adjustment but outside the FRP bandwidth formula. In the 2021 FRP proceeding, the Project's associated revenues and non-fuel revenue requirement would be included in the FRP bandwidth formula and recovered through the FRP Rate Adjustment.

XXXVII.

Once the Project commences commercial operation, ENO will begin incurring expenses related to the Project that are not expected to be reflected in ENO's base rates at the time. If the Council takes no action to address recovery of these expenses, then those expenses will have an adverse effect on ENO's financial condition. In the event that there is no FRP in place after the Combined Rate Case, ENO proposes that the Project's non-fuel revenue requirement be recovered through the PPCACR Rider or a similar exact cost recovery rider until such time that ENO's base rates are reset.

XXXVIII.

As part of its requests, the Company proposes a Monitoring Plan whereby the Company would make periodic progress reports to the Advisors and the Council during the construction phase. The Monitoring Plan will serve as an "early warning system," and the Company commits to providing the Council in the quarterly reports an affirmation as to whether continuing the Project is, in their opinion, in the public interest. The Company requests that the Council require the Advisors to acknowledge the report, in writing, and submit any questions regarding the report within 30 days.

XXXIX.

As explained in the Direct Testimony of Ms. Shauna Lovorn-Marriage, in the event that circumstances change significantly after Council approval such that the Company believes it to be in the public interest to cease construction and/or cancel the Project, it will make a filing in this proceeding seeking Council approval of that recommendation. In this Application, the Company seeks approval of this procedure.

XL.

As discussed by Mr. Breedlove in his Direct Testimony, ELL is negotiating an LTSA for the maintenance of NOPS' combustion turbine with the OEM. The LTSA is expected to have a structure and scope similar to other LTSAs recently entered into by ELL or its affiliates providing for a defined scope of major maintenance activities. As explained by Mr. Todd in his Direct Testimony, the costs for major maintenance services included on the base scope of work of the LTSA are expected to be variable costs that depend on the number of unit starts and hours of run-time. Therefore, the Company proposes that these variable costs be recovered through the FAC, as the Council has previously authorized for LTSA expenses associated with the Nine Mile 6 Unit and Union Power Station Power Block 1.

REQUEST FOR TIMELY TREATMENT

XLI.

The Company also requests that the Council issue the approvals requested herein no later than January 31, 2017. This procedural schedule will allow the Company to issue timely NTP to the EPC contractor selected for the Project. As discussed, the estimated cost to construct NOPS assumes that the Company is able to issue NTP no later than [redacted], following receipt of acceptable approvals from the Council, which issuance is expected to result in commercial operation of NOPS in October 2019. The inability of the Company to issue NTP by [redacted] would cause at least a day-for-day slip in the Project schedule and price escalation under the EPC contract, as discussed in the Direct Testimony of Mr. Jonathan Long.

XLII.

Thus, In order to facilitate a January 2017 decision, the Company proposes the following Procedural Schedule:

Discovery	**Issue Date of Procedural Schedule** **Resolution to 15 days prior to hearing**
Direct Testimony of Intervenors	**October 3, 2016**
Direct Testimony of Advisors	**October 24, 2016**
Rebuttal Testimony of ENO	**November 14, 2016**
Evidentiary Hearing	**December 5, 2016**
Hearing Officer to Certify Record	**December 12, 2016**
Council Decision	**by January 31, 2017**

SERVICE OF NOTICES AND PLEADINGS

XLIII.

The Company request that notices, correspondence, and other communications concerning this Joint Application be directed to the following persons:

Gary E. Huntley
Vice President, Regulatory and
Governmental Affairs
Entergy New Orleans, Inc.
1600 Perdido Street
New Orleans, Louisiana 70112

Karen F. Freese
Timothy S. Cragin
Brian L. Guillot
Alyssa Maurice-Anderson
Harry M. Barton
Entergy Services, Inc.
639 Loyola Avenue
Mail Code: L-ENT-26E
New Orleans, Louisiana 70113

REQUEST FOR CONFIDENTIAL TREATMENT

XLIV.

Portions of the supporting Direct Testimony and exhibits contain information considered by ENO to be proprietary and confidential. Public disclosure of certain of this information may expose ENO and its customers to an unreasonable risk of harm. Therefore, in light of the commercially sensitive nature of such information, the Company prepared two versions of the Direct Testimony of Messrs. Rice, Todd, John Long, Charles Long, Breedlove, and Ms. Lovorn-Marriage, and accompanying exhibits, one marked "Non-Confidential Redacted Version" and the other marked "Confidential Version." In anticipation of the execution of confidentiality agreement by parties in this docket, the Confidential Versions bear the designation "Highly Sensitive Protected Materials" or words of similar import. The confidential information and documents included with the Application may be reviewed by appropriate representatives of the Council and its Advisors pursuant to the provisions of the Official Protective Order adopted in Council Resolution R-07-432 relative to the disclosure of Highly Sensitive Protected Materials. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

PRAYER FOR RELIEF

XLV.

WHEREFORE, Entergy New Orleans, Inc. respectfully requests that the Council, subject to the fullest extent of its jurisdiction, grant relief and give its approval as follows:

1. Find that the Company's construction of NOPS serves the public convenience and necessity and is in the public interest, and is therefore prudent.

2. Confirm that the Company's investments made pursuant to a public interest determination by the Council are presumed prudent and eligible for recovery from

customers, and that the Company will have a full and fair opportunity to recover all prudently-incurred costs of the Project;

3. Find that the retail non-fuel revenue requirement associated with the Project (to be determined in a subsequent revenue requirement filing) is deemed eligible for recovery in the first billing cycle of the month following commercial operation of NOPS via applicable PPCACR Rider, which would be modified for such purpose, or a similar exact cost recovery rider;

4. Approve recovery, though the applicable FAC, of the energy costs and expenses incurred under NOPS' LTSA;

5. Approve the Monitoring Plan under which the Company will: (i) report to the Council Advisors on a quarterly basis the status of NOPS, including schedule, costs, and other critical associated activities, and (ii) receive written acknowledgment from the Council Advisors;

6. Rule that, with respect to the Project described in the Application, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions;

7. Grant a waiver of any applicable requirement to the extent that such a waiver may be required to facilitate approval of the transaction described in this Application;

8. Develop and implement appropriate procedures to facilitate a Council decision on the Application no later than January 31, 2017; and

9. Order such other general and equitable relief as to which the Company may show itself entitled.

Respectfully Submitted:

By: ______________________________

Karen H. Freese, Bar No. 19616
Timothy S. Cragin, Bar No. 22313
Brian L. Guillot, Bar No. 31759
Alyssa Maurice-Anderson, Bar No. 28388
Harry M. Barton, Bar No. 29751
639 Loyola Avenue, Mail Unit L-ENT-26E
New Orleans, Louisiana 70113
Telephone: (504) 576-2603
Facsimile: (504) 576-5579

ATTORNEYS FOR ENTERGY NEW ORLEANS, INC.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-______**

DIRECT TESTIMONY

OF

CHARLES L. RICE, JR.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles L. Rice, Jr. I am President and Chief Executive Officer of Entergy New Orleans, Inc. ("ENO" or the "Company"). My business address is 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of ENO.

Q3. WHAT ARE YOUR CURRENT DUTIES?

A. As President and Chief Executive Officer of ENO, a position I have held since June 2010, I have executive responsibility for the Company, which includes responsibility for the production, transmission, and distribution assets that are used to serve ENO's customers.

Q4. PLEASE DESCRIBE BRIEFLY YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND WORK EXPERIENCE.

A. I earned a Bachelor of Science degree in Business Administration from Howard University in 1986. Following graduation, I was commissioned as a second lieutenant in the United States Army and served as a military intelligence officer with the 101st Airborne Division (Air Assault). In 1995, I earned a Juris Doctorate from Loyola University New Orleans School of Law. Upon admission to the Louisiana Bar, I began practicing law with the firm of Jones, Walker, Waechter, Poitevent, Carrère & Denègre, LLP. In 2000, I joined the Legal Department of Entergy Services, Inc. ("ESI").[1] In ESI's Legal Department, I held the position of Senior Counsel and was a member of the Casualty Litigation group. Shortly thereafter, I transferred to the Human Resources Department, where I served as Manager of Labor Relations Litigation Support.

In 2002, I left ESI to serve in local government as the City Attorney for the City of New Orleans. I later served as Chief Administrative Officer for the City of New Orleans, in which role I managed 6,000 employees and the City's $600 million budget. In 2004, I returned to private law practice as a partner with the law firm of Barrasso, Usdin, Kupperman, Freeman & Sarver, LLC. In 2009, I returned to Entergy to serve as Director of Utility Strategy for ESI. In that role, I was responsible for coordinating regulatory, legislative and communications efforts for Entergy's regulated utility companies. In early 2010, I transferred to ENO to lead the Regulatory Affairs Department, and, in June 2010, I was promoted to my current position. I also earned an Executive Master of Business Administration degree from Tulane University in 2012.

A listing of my previous testimony is attached hereto as Exhibit CLR-1.

II. <u>PURPOSE OF TESTIMONY</u>

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In its Application for Approval to Construct New Orleans Power Station ("NOPS") and Request for Cost Recovery and for Timely Relief ("Application"), ENO is seeking a public interest determination from the Council regarding ENO's proposed construction of

[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Inc. ENO, and Entergy Texas, Inc. ("ETI").

a 226 MW combustion turbine ("CT") generating unit to be located at the Company's Michoud generating facility in Orleans Parish, Louisiana. My testimony supports the Application.

Q6. WHY IS ENO PROPOSING TO CONSTRUCT NOPS?

A. As discussed more fully by Company witness Seth E. Cureington, ENO has a need for overall capacity as well as a need for local peaking and reserve capacity resources. The recent deactivations of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational issues, resulted in the loss of approximately 781 MW of local capacity (which is approximately [redacted] of ENO's 2016 forecasted non-coincident peak load). NOPS will provide a modern, cost-effective, and local source of generating capacity capable of meeting ENO's long-term overall capacity needs as well as a significant portion of its peaking and reserve supply role needs. ENO's need comes at a time when market equilibrium is fast approaching in MISO South, which is the point at which there will no longer be excess capacity available for purchase in the wholesale market, causing capacity prices to sharply increase. NOPS will mitigate such market exposure for customers.

Moreover, as discussed by Mr. Cureington, ENO considered various alternatives, including demand-side management ("DSM") and renewable resources, and determined that NOPS is the most economic option to satisfy customers' capacity and reliability needs. Moreover, NOPS will improve the reliability of the electric grid in the City of New Orleans. As discussed more fully by Company witness Charles W. Long, the construction of NOPS will have the effect avoiding large-scale transmission projects that would otherwise be necessary to maintain reliability in New Orleans. It is also important to note that, as discussed more fully below and by Mr. Charles Long, NOPS will also be a highly-reliable quick-start generator, which will aid in shortening the time to restore service to customers after large-scale events such as hurricanes or other natural disasters. Thus, NOPS is consistent with the Council's stated objective to harden the system in preparation for major weather events.

If ENO receives the approvals requested from the Council of the City of New Orleans ("Council"), and there are no unanticipated project delays related to the procurement of all of the necessary permits, materials, and supplies, NOPS is expected to enter service in the second half of 2019.

Q7. PLEASE ELABORATE ON NOPS' ABILITY TO AID IN STORM RESTORATIONS?

A. As discussed more fully by Messrs. Cureington and Charles Long, NOPS adds a local source of active or "real" power in the Downstream of Gypsy ("DSG") load pocket with the ability to start quickly. This can aid in shortening the time to restore service to customers after large scale events such as hurricanes or other natural disasters. For example, if the transmission system experiences extensive damage during a hurricane, which has occurred in the New Orleans area, the ability to import power across the transmission lines may be impaired for many days due to transmission system damage. In such a scenario, local generation units make it possible to locally supply power through a smaller number of relatively short transmission lines that can be repaired more quickly. A unit like the proposed NOPS provides a "starting point" for restoration and allows restorations to occur more quickly than would be possible relying solely on transmission facilities. A local generator, such as the NOPS, will also greatly aid in maintaining the integrity of the electric system in the event that a storm severs the electric grid in a manner that creates an electrical island. In fact, as discussed by Mr. Charles Long, this phenomenon has in-fact occurred during Hurricane Gustav.

Q8. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY AND THE RELIEF SOUGHT BY ENO?

A. My testimony begins with a general description of the proposed NOPS facility and then provides an overview of the Application. I also introduce the witnesses supporting the Application. The testimonies and exhibits included with this filing demonstrate that the Company has a current need for long-term peaking/reserve resources; that the Project is the lowest reasonable cost alternative, considering relevant risk factors, to meet those needs; and that the Company's construction of NOPS would therefore serve the public convenience and necessity.

ENO requests that the Council grant its Application in its entirety and implement a regulatory process that ensures the ability to issue full notice to proceed by the end of January 2017.

III. <u>NOPS DESCRIPTION</u>

Q9. PLEASE BRIEFLY DESCRIBE THE PROJECT CONTEMPLATED BY THE APPLICATON.

A. NOPS will be a natural-gas-fueled CT generating facility with a nominal capacity of approximately 226 megawatts ("MW"), at summer conditions. Company witnesses Jonathan E. Long and Robert A. Breedlove discuss the technical and operating characteristics of the facility. As I discuss further below, NOPS will be constructed on property owned by ENO in Orleans Parish. If the Company receives the approvals requested from the Council, and there are no unanticipated project delays related to the procurement of all of the necessary permits, materials, and supplies, the Project is expected to enter service in the second half of 2019. Mr. Jonathan Long discusses the Project's schedule in his testimony and the importance of issuing a notice to proceed to the Project's principal contractor on or before [redacted]. Accordingly, the Company is requesting that the Council establish a Procedural Schedule, as more fully described below, that would allow it to issue a Council decision no later than January 31, 2017.

Q10. WHERE DOES THE COMPANY PLAN TO CONSTRUCT NOPS?

A. NOPS is proposed to be located in New Orleans, Louisiana. The proposed Project site is ENO's Michoud facility, which is located in an industrial area on the eastern edge of New Orleans, and bounded generally by Old Gentilly Road to the North, Paris Road to the West, and the Intracoastal Waterway to the South, and East. Based on local considerations, and in accordance with the Council's directive in Resolution R-15-524, which directed the Company to use "reasonable diligent efforts" to pursue development of a peaking resource in the City following termination of the Entergy System Agreement, the site selection process involved identification of potential locations for the development of new generation in Orleans Parish. Considering factors related to fuel supply, transmission, existing infrastructure, site suitability, and environmental regulations, the Company selected the Michoud site for the construction of NOPS.

Figures 1 (upper right hand corner) and 2 below reflect the proposed location of NOPS.

Figure 1 – Location of Proposed NOPS

Figure 2 – Aerial View of Proposed Location of NOPS

Q11. WHAT IS THE COST OF THE PROJECT?

A. The current cost estimate of the Project is $216 million, or roughly $955 per kW, which estimate is inclusive of, among other things, expenses related to seeking Council approval, certain transmission costs, contingency, and an allowance for funds used during construction ("AFUDC"). Mr. Jonathan Long discusses this estimate, including how it was developed and the cost components that are included.

Q12. ARE ANY TRANSMISSION OR INTERCONNECTION UPGRADES NEEDED FOR THE PROJECT?

A. Yes. As Mr. Charles Long describes, as with any interconnecting generator, there are three different categories of upgrades and associated costs that may be required. These include transmission upgrades that are necessary to: (1) physically connect the generator to the electrical system, (2) designate the resource as a Network Resource, and (3) mitigate any reliability issues under the North American Electric Reliability Corporation ("NERC") Reliability Standards and/or Planning Criteria that may result from the interconnection of the generator. Mr. Long lists the specific interconnection upgrades that are required for the Project in the first category, along with their corresponding cost estimates. He also describes the process used to identify the necessary upgrades in the latter two categories, certain of which have not yet been definitively determined.

Q13. WILL THE COMPANY USE A THIRD-PARTY ENGINEERING, PROCUREMENT, AND CONSTRUCTION CONTRACTOR FOR THE PROJECT?

A. Yes. The Company has selected Chicago Bridge & Iron, Inc. ("CB&I") to provide engineering, procurement, and construction ("EPC") services for the Project as a result of a competitive procurement process, as discussed by Mr. Jonathan Long. The Project will be constructed by CB&I under a fixed-price, fixed-schedule-duration form of EPC contract, similar to what was successfully used for Ninemile 6. Mr. Jonathan Long describes how the Company selected CB&I, the terms of the EPC contract, and CB&I's responsibilities in connection with the Project. CB&I was the EPC contractor for Ninemile 6, in which ENO has a 20% life-of-unit PPA. The Company followed the same contracting approach for NOPS that resulted in the successful, timely, and under-budget completion of Ninemile 6.

Q14. PLEASE BRIEFLY DESCRIBE THE NEED FOR NOPS.

A. As explained by Mr. Seth Cureington, the recent deactivations of Michoud Units 2 and 3 resulted in the loss of approximately 781 MW of local capacity (which is approximately [redacted] of ENO's 2016 forecasted non-coincident peak load). As a result, ENO has a need for overall capacity as well as a need for local peaking and reserve capacity resources. This need comes at a time when the capacity market in MISO South is expected to tighten, reaching equilibrium (the point at which supply and demand meet) by 2022. Thus, deferring construction of a new resource comes with considerable risk considering the long lead-time necessary to gain regulatory approval of, plan, and construct new resources; potential cost premiums for parts and equipment as other utilities are simultaneously shifting to modern, gas-fired resources; and expected sharply higher and more volatile capacity prices during that time frame.

As is also explained more fully by Mr. Seth Cureington, NOPS is consistent with the results of ENO's 2015 Integrated Resource Plan ("IRP"), filed in Docket No. UD-08-02 on February 1, 2016 (Exhibit SEC-7). The IRP identifies a Preferred Portfolio for meeting customers' long-term needs at the lowest reasonable cost, while considering reliability and risk. The IRP identified an overall long-term need for capacity as well as a need for long-term peaking and reserve resources. Through the DSM Potential Study, Generation Technology Assessment, and Portfolio Evaluation phases of the IRP, the Company conducted a thorough evaluation of a range of viable supply and demand-side alternatives capable of meeting those needs. The results of the Final 2015 IRP support the conclusion that a CT is the lowest reasonable cost resource addition capable of meeting the Company's overall capacity needs (including the target planning reserve margin ("PRM") of 12%), and a substantial portion of the identified peaking and reserve capacity need.

Q15. DOES NOPS OFFER RELIABILITY-RELATED BENEFITS?

A. Yes. As explained in more detail by Mr. Charles Long, the construction of NOPS will result in the avoidance of transmission-related projects that would otherwise be necessary to ensure reliability. In addition, because NOPS will be constructed in proximity to the load it will serve, the unit will increase the load-serving capability in New Orleans, lower dependence on transmission facilities to serve the area, increase operational flexibility for generation and transmission maintenance facilities in the area, increase reactive power, and aid in storm restorations.

Q16. HAS THE COMPANY EVALUATED THE CT AGAINST OTHER AVAILABLE ALTERNATIVES?

A. Yes. As Company witness Seth E. Cureington explains, CT resources, such as NOPS, are technologically suited not only to supply capacity, but for serving peaking and reserve roles, for which ENO has a specific need. Renewable resources such as wind and solar photovoltaic ("PV") are intermittent, as they rely on the wind and sun to produce energy, thus limiting the ability to rely on them to meet customer demand. As a result, renewables must be supported by dispatchable resources such as CTs to ensure sufficient resources are available to ramp-up and produce replacement energy when the wind is either not blowing or blowing less than projected, and similarly when cloud cover or unexpected weather limits the output of solar PV. In addition, even if the cost of wind and solar PV were comparable in cost to conventional alternatives and even if these resources could meet ENO's specific supply-role needs (which they cannot), it is reasonable to expect that the total cost to acquire sufficient renewable capacity to meet ENO's long-term needs would exceed the cost of conventional alternatives because the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs, precisely because they are intermittent.

Mr. Seth Cureington also explains that in the 2015 IRP, the Company evaluated the feasibility of Demand Side Management ("DSM") programs to meet its planning needs. The result of that study was that DSM programs offer opportunities to meet some level of long-term capacity needs, but not enough to meet those needs in their entirety. For example, in the 2015 IRP, ICF International ("ICF") conducted an analysis of the long-term DSM potential achievable in New Orleans and found that by 2019, only approximately 49 MW of cumulative peak demand could be avoided through cost-effective DSM programs. The Company's need for peaking and reserve capacity, however, is 376 MW, far exceeding the achievable level of DSM in that timeframe. Thus, it was determined that the Company cannot rely on renewable and DSM to meet all of its specific planning needs.

The Company also evaluated the specific technology selected for NOPS, the Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC large frame CT, against other possible CT technologies to ensure that it is the most favorable technology for NOPS. This assessment evaluated the alternative technologies against a range of factors, including fixed and total supply cost, operational flexibility, ENO's needs, and gas pressure requirements. The results of that assessment, as discussed by Mr. Cureington, showed that selection of the MHPSA 501 GAC fits ENO's planning needs because it provides the highest capacity rating and lowest total supply cost of seven technologies that were evaluated.

Q17. IS THE PROJECT EXPECTED TO PROVIDE BENEFITS IN ADDITION TO THE PLANNING BENEFITS DISCUSSED IN THE TESTIMONIES OF MESSRS. CUREINGTON AND CHARLES LONG?

A. Yes. In June 2016, Loren C. Scott & Associates, Inc.[2] studied the effect that construction of the Project is expected to have on the economies of the State of Louisiana and Orleans Parish. That study concluded that the construction and operation of NOPS will produce significant economic benefits – totaling hundreds of millions of dollars – in terms of new business sales, household earnings, and jobs in both the State and regional economies. Benefits result not only from one-time capital expenditures, but also from ongoing operational expenditures that will continue to accrue to the benefit of residents in the region and State as long as NOPS is in operation.

[2] Economic Impact on the Orleans Parish and Louisiana Economies of New Orleans Power Station, Loren Scott & Associates, Inc., May 2016, attached as Exhibit CWL-2.

Q18. ARE THERE ANY ENVIRONMENTAL CONSIDERATIONS OF WHICH THE COUNCIL SHOULD BE AWARE?

A. Yes. As Company witness Jonathan Long explains, the NOPS will use newer, cleaner, and more efficient technology than the recently deactivated units at the Michoud site. This means that NOPS will produce significantly lower emission levels than the recently deactivated units.

Moreover, although ENO does not believe any material impacts resulted from groundwater usage by the deactivated Michoud units, the Council should be aware that NOPS will result in a substantial decrease in the capacity for groundwater usage when compared to the recently deactivated units. Considering the absolute maximum *possible* groundwater usage for NOPS, there is expected to be a reduction of 90% in comparison to the deactivated Michoud units. Moreover, considering the maximum *expected* groundwater usage for NOPS, there is expected to be a reduction of approximately 99%.

IV. <u>OVERVIEW OF THE APPLICATION</u>

Q19. WHAT IS THE PURPOSE OF THE COMPANY'S APPLICATION?

A. The purpose of the Application is to request that the Council find that the Project would serve the public convenience and necessity and is in the public interest. In addition, the Company is requesting the following findings by the Council:

- that the Project complies with applicable Council Orders regarding the construction of resources;
- approval of the proposed Monitoring Plan for the Project;

- approval of the proposed In-Service Cost Recovery Plan that would take effect after the plant goes into service, which is discussed in the direct testimony of Company witness Orlando Todd;
- approval for recovery though the Fuel Adjustment Clause ("FAC") of the variable operation and maintenance expenses incurred under long-term service agreements ("LTSA") covering the Project, which is discussed in the Direct Testimonies of Company witnesses Robert A. Breedlove and Orlando Todd;
- confirmation that the investments made pursuant to a public interest determination by the Council are prudent and that the Company will have a full and fair opportunity to recover prudently incurred costs of the Project.

Q20. PLEASE SUMMARIZE THE PROPOSED REGULATORY APPROVAL PLAN.

A. As Company witness Ms. Shauna Lovorn-Marriage explains, this proceeding presents possibly the first time in more than thirty years that the Company has asked the Council to approve the construction of a generating unit by ENO. The requested regulatory approvals and findings are important to ENO because they will give the Company the certainty that it will have a reasonable opportunity to recover its prudently incurred costs associated with the construction of the NOPS. Without that certainty, the Company could not responsibly undertake the investment necessary to construct the NOPS.

The Company proposes a process whereby the Council would issue a decision, supported by the evidence and sound regulatory principles, that the construction of the Project is in the public interest and therefore prudent. As part of this decision, the Council would approve an In-Service Cost Recovery Plan, which is discussed by Mr.

Orlando Todd. In the past, the Council has allowed timely recovery of the costs associated with new resources obtained for the benefit of ENO's customers, such as Union Power Block 1 and the PPA with respect to Ninemile 6. Such rate treatment provides an incentive for ENO to continue to undertake large investments or obligations in order to secure benefits for its customers.

The Company also proposes that the Council approve a Monitoring Plan whereby the Company would make periodic progress reports to the Council Advisors during the construction phase.

Q21. WHEN DOES ENO REQUEST THE COUNCIL GRANT THE NECESSARY REGULATORY APPROVALS?

A. ENO asks that the Council take the steps needed to establish a Procedural Schedule such that the Council would issue a decision on this Application no later than January 31, 2017. This time table will provide adequate time for the Council, its Advisors and any stakeholders to review and provide comment on the Application and the Project, while also permitting ENO to commence construction in time to achieve substantial completion on or before October 1, 2019, as discussed in the testimony of Mr. Jonathan Long. In order to facilitate a January 2017 decision, the Company proposes the following Procedural Schedule:

Discovery	**Issue Date of Procedural Schedule Resolution to 15 days prior to hearing**
Direct Testimony of Intervenors	**October 3, 2016**
Direct Testimony of Advisors	**October 24, 2016**
Rebuttal Testimony of ENO	**November 14, 2016**
Evidentiary Hearing	**December 5, 2016**
Hearing Officer to Certify Record	**December 12, 2016**
Council Decision	**by January 31, 2017**

V. INTRODUCTION OF WITNESSES

Q22. PLEASE INTRODUCE THE OTHER WITNESSES FILING TESTIMONY ON BEHALF OF ENO AND IDENTIFY THE SUBJECTS THAT EACH ADDRESSES.

A. In addition to my testimony, ENO's Application is supported by the testimony of the following witnesses:

- **Orlando Todd –** Mr. Todd is the Finance Director for ENO. Mr. Todd provides the estimated first-year revenue requirement associated with the Project. He also describes the proposal to recover, through ENO's FAC, the variable costs associated with the LTSA that ENO will enter into in connection with certain major maintenance activities for NOPS. In addition, Mr. Todd explains the proposed Cost Recovery Plan and the importance of timely recovery with respect to the costs related to the Project.
- **Seth E. Cureington –** Mr. Cureington is the Manager, Resource Planning and Market Operations for ENO. Mr. Cureington discusses the Company's long-term resource planning process, the Company's long-term resource needs, including a need for local peaking and reserve capacity resources, and how the Project addresses those needs. He also describes the supply conditions in MISO South that are expected to tighten by planning year 2022. Finally, Mr. Cureington discusses the site selection for the Project.

- **Jonathan E. Long** – Mr. Jonathan Long is the Vice President, Project Management for ESI. He provides an overview of the Project, explains how the cost estimate associated with the Project was developed, and provides the current cost estimate and schedule for the Project. He also describes the management approach that the Company intends to employ and the process used to select the EPC contractor for the Project. Finally, Mr. Jonathan Long discusses the status of the required permits/approvals for the Project.
- **Charles W. Long** – Mr. Charles Long is the Director of Transmission Planning for ESI. He describes, from the transmission perspective, the unique characteristics of the DSG region and how the construction of NOPS will have the effect of avoiding/delaying projects that would otherwise be necessary to maintain reliability. Mr. Long also describes the transmission related reliability benefits associated with constructing NOPS and the process MISO uses to identify transmission upgrades that may be necessary for the integration of NOPS into the electric grid.
- **Shauna Lovorn-Marriage** – Ms. Lovorn-Marriage is the Director, Regulatory Filings for ESI. Ms. Lovorn-Marriage discusses the regulatory and ratemaking issues that will need to be resolved in order for the Company to initiate and successfully complete the Project at the lowest reasonable cost. Specifically, she (1) sets forth approvals required by the Company before committing significant capital to build the Project; (2) discusses the Company's compliance with applicable Council Orders; (3) sets forth the specific requested findings concerning the public interest; (4) discusses why the approval of the Project is in

the public interest; and (5) discusses the proposed plan by which the Staff can monitor the progress of the construction of NOPS.

- **Robert A. Breedlove –** Mr. Breedlove is the Director of Plant Support in Fossil Operations. Mr. Breedlove provides a general description of CT technology, including how that technology has developed. He also describes the estimated operation and maintenance costs for the Project. Finally, he describes the Company's plan to manage major maintenance on the Project's major equipment through the long-term service agreement.

VI. CONCLUSION

Q23. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. ENO is requesting the Council's timely consideration of its Application for approval to construct NOPS, which would provide approximately 226 MW of CT capacity, which will provide a modern, cost-effective and local source of generating capacity capable of meeting ENO's long-term overall capacity needs as well as a significant portion of its peaking and reserve supply role capacity needs. NOPS will improve supply conditions in the Company's service area by providing a long-term resource capable of supporting reliable service to New Orleans during periods of peak demand and unplanned events, and it will mitigate market and supply related risks, particularly as equilibrium approaches. NOPS will also contribute to reliability in New Orleans and provide reliability benefits such as support for restoration efforts following major weather events. In short, the testimonies and exhibits included with this filing demonstrate the Company's current needs at the lowest reasonable cost to customers considering risks, and the Council should approve ENO's Application in a timely manner.

Q24. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES RICE, JR.**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Charles Rice, Jr.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 13th DAY OF JUNE, 2016

NOTARY PUBLIC

My commission expires: at death

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life

Previous Testimony of Charles L. Rice				
TYPE OF TESTIMONY	**JURISDICTION**	**CLIENT**	**DOCKET**	**Filing Date**
Direct Testimony	CNO	ENO	UD-07-03	11/1/2010
Supplemental Direct Testimony	CNO	ENO	UD-07-03	1/4/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	2/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	3/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	4/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	5/2/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	5/12/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	6/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/12/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/3/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/14/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/3/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/2/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/4/2012
Direct Testimony	CNO	ENO	UD-12-01	9/12/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/3/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/2/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/4/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/3/2013
Rebuttal Testimony	CNO	ENO	UD-12-01	6/12/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2013

Previous Testimony of Charles L. Rice

TYPE OF TESTIMONY	JURISDICTION	CLIENT	DOCKET	Filing Date
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/3/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/2/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/2/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/3/2014
Direct Testimony	CNO	ENO	UD-14-01	2/28/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/3/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/2/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/2/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/1/2014
Direct Testimony	CNO	ENO	UD-14-02	10/30/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/2/2015
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/3/2015
Direct Testimony	CNO	ENO	UD-15-01	2/8/2015
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/2/2015
Supplemental Direct Testimony	CNO	ENO	UD-15-01	8/21/2015

ECONOMIC IMPACT ON THE ORLEANS PARISH AND LOUISIANA ECONOMIES OF ENTERGY'S PROPOSED NEW ORLEANS POWER STATION

PREPARED BY

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May 2016

Executive Summary

Entergy New Orleans, Inc. ("ENOI") plans to construct a new simple cycle power plant called the New Orleans Power Station (NOPS) that will be located within the boundary of the property on which the existing Michoud Generating Plant in New Orleans, Louisiana. The company is proposing to install one MHI 501GAC-FAST "G" Class gas Combustion Turbine Generator (CTG) in a simple Cycle Gas Turbine (SCGT) configuration. This plant will use natural gas as its sole fuel source. The NOPS has a predicted output capacity of a nominal 246 megawatt (MW). The gas turbine will be connected to the existing 115 kilovolt (KV) switchyard at the site. This state-of-the-art technology offers environmental benefits, while also offering the economic benefits of a high fuel-use efficiency rate.

The purpose of this report is to estimate the impact of constructing and then operating this new plant on the (1) Orleans Parish and (2) State of Louisiana economies, using input-output tables produced by the U.S. Bureau of Economic Analysis. Our findings can be summarized as follows:

The impacts of spending $153.3 million in-state to **construct** the NOPS over the six years from 2015 to 2020 are:

- Impacts on **Orleans Parish** economy:
  - $205,881,900 in new sales at Companies in the parish;
  - $28,115,220 in new earnings for parish residents;
  - An average of 92 jobs a year, and;
  - $982,749 in new sales tax collections for the parish treasury.
- Impacts on the **Louisiana** economy:
  - $304,346,490 in new sales at Companies in the state;
  - $102,496,380 in new earnings for state residents;
  - An average of 351 jobs a year in the state, and;
  - $7,174,747 in new revenue collections for the state treasury.

Table E-1 summarizes the annual impacts on the parish and state economies of **operating** this plant once it is built. While the construction impacts bulleted above are temporary and vanish once construction ends, the impacts in Table E-1 are on-going and indeed, will likely grow over time due to inflation.

Table E-1
Impacts of Operating the NOPS on the Orleans Parish & Louisiana Economies

Category	Orleans Parish Impacts	State Impacts
New Business Sales	$3,171,918	$4,703,366
New Household Earnings	$2,283,881	$3,313,161
New Permanent Jobs	23	46
Taxes	$79,936	$231,921

Table of Contents

I. Introduction

Entergy New Orleans, Inc. ("ENOI") plans to construct a new simple cycle power plant called the New Orleans Power Station (NOPS) that will be located within the boundary of the property on which the existing Michoud Generating Plant in New Orleans, Louisiana. The company is proposing to install one MHI 501GAC-FAST "G" Class gas Combustion Turbine Generator (CTG) in a simple Cycle Gas Turbine (SCGT) configuration. This plant will use natural gas as its sole fuel source. The NOPS has a predicted output capacity of a nominal 246 megawatt (MW). The gas turbine will be connected to the existing 115 kilovolt (KV) switchyard at the site. This state-of-the-art technology offers environmental benefits, while also offering the economic benefits of a high fuel-use efficiency rate.

NOPS will be constructed over the 6-year period from 2015 to 2020. The middle column of Table 1 shows the pattern of these expenditures over these six years. Of the total construction cost of $216 million, it is estimated that $63 million will be spent on equipment purchased out-of-state. The last column of Table 1 shows the in-state expenditures after deducting this $63 million. The total in-state construction spending will be $153.3 million.

Table 1
Schedule for Construction of the New Orleans Power Station
($millions)

Year	Total Construction Costs	In-State Construction Spending
2015	$1.6	$1.6
2016	$3.0	$3.0
2017	$47	$24.7
2018	$118	$83.8
2019	$46	$40.0
2020	$0.2	$0.2
Total	**$216**	**$153.3**

This report is focused on estimating the impact of both constructing and operating the NOPS on the economies of Orleans Parish and the State of Louisiana. In each region impacts will be estimated on (1) business sales, (2) household earnings, (3) jobs, and (4) tax collections. Section II describes the methodology used to estimate the multiplier effect of this new spending. Section III is devoted to the impacts of constructing and operating the NOPS on the Orleans Parish economy, while Section IV examines the impact of this spending on the State's economy. Finally, Section V contains a summary and conclusions.

II. Methodology

It is a well-established principle that business investment decisions have both direct and indirect (secondary) impacts on the economy. The direct impact of a particular company or establishment on income and employment can be measured by its revenue and payroll. However, these impacts would significantly understate the role of the company in the economy. The reason is that the company also buys from, and sells to, many other companies in the economy. The interactions caused by these purchases and expenditures are magnified by the spending of employees who earn income from the company and the affected businesses.

Thus, any change in the activity of a particular company **indirectly** affects these buyers and sellers, which in turn affects companies that buy from and sell to these buyers and sellers, etc. For example, when a decision is made by a company that creates a new job, a chain-reaction is started which works its way throughout the economy. This chain-reaction (multiplier effect) causes even more jobs to be created. The analogy is of a rock being tossed into a pond. Not only is there an initial splash, but ripples are also created that spread throughout the pond.

The major difficulty lies in attempting to quantify these indirect or multiplier effects. Fortunately, a technique has been developed for precisely this purpose---an input-output (I/O) table. An I/O table is a matrix of numbers that describes the interactions between all industries in a geographical area (in this case, the state and the region). The I/O table provides a complete picture of the flows of products and services in the economy for a given year, illustrating the relationship between producers and consumers and the interdependencies of industries in the state. I/O tables for Orleans Parish and the State of Louisiana have been constructed by the Bureau of Economic Analysis (BEA) in the U.S. Department of Commerce. The BEA is the government agency responsible for measuring the nation's gross domestic product each quarter. An I/O table can be used to estimate three separate impacts generated by the capital outlays and operational expenditures by ENOI on the NOPS: (1) *new sales* for companies in the parish and the state, (2) *new household earnings* for residents in the parish and the state, and (3) *new jobs* in the parish and the state.

III. Impact of NOPS Capital & Operational Spending on Orleans Parish

In this section the impact of the new NOPS project is assessed on the economy of Orleans Parish. The impact of constructing the facility is discussed first, followed by the impact of operating the plant once construction is completed.

Impact of Constructing the NOPS on Orleans Parish

As shown in Table 1, the NOPS will be constructed over the 6-year period from 2015 to 2020. The last column of that table shows how the total of $153.3 million of in-state spending will be allocated over those six years. The majority of this spending will occur over 2017-19, with the peak spending year being 2018 ($83.8 million).

These in-state construction data were plugged into the I/O table for Orleans Parish to determine the multiplier effects of this spending on the parish's economy. The results are shown in Table 2.

Table 2
Impacts of Construction of the NOPS on Orleans Parish

Years	Sales	Earnings	Jobs	Taxes
2015	$2,148,800	$293,440	6	$10,270
2016	$4,029,000	$550,200	11	$19,257
2017	$33,172,100	$4,529,980	90	$158,549
2018	$112,543,400	$15,368,920	301	$537,912
2019	$53,720,000	$7,336,000	142	$256,760
2020	$268,600	$36,680	1	$1,284
Total	**$205,881,900**	**$28,115,220**	**92**	**$982,749**

According to the parish I/O table spending to construct the NOPS over 2015-20 will create (1) $205.9 million in new business sales in the parish, (3) $28.1 million in new household earnings for parish residents, and (3) an average of 92 jobs a year. Not surprisingly, the largest impacts are in the years of greatest construction spending---2017, 2018, and 2019. In the peak year of spending (2018), construction activity will create $112.5 million in new business sales in the parish and $15.4 million in new household earnings for parish residents. In that year, over 300 jobs will be supported in the parish.

It is also possible to estimate how much new sales taxes the parish will collect due to the construction of the NOPS. For example, in 2012 the parish collected just over $324 million in sales tax collections.[1] In that same year parish residents made $9,745.2 million in earnings.[2] Thus, it is estimated that for every dollar of earnings, the parish collects 3.5 cents ($324 million/$9,745.2 million) in sales taxes.

By multiplying the new earnings numbers in column two of Table 2 by 3.5% we arrive at the new sales tax estimates in the last column of Table 2. **It is estimated that the construction of the NOPS will pump an additional $982,749 in new sales taxes into the parish treasury**.

Impact of Operating the NOPS on Orleans Parish

Once the NOPS construction is completed, new monies will be injected into the parish economy to operate the plant. ENOI estimates it will spend just over $6.7 million a year to operate the facility. Of this $6.7 million, $1,456,386 will be spent on payroll. An even bigger expense for the plant will be $3,764,310 for a long term service agreement. Only an estimated 7% of these LTSA monies are expected to be spent in-state. About $620,000 will be spent annually on regular maintenance at the NOPS. The new plant is expected to employ 12 new full time employees.

Table 3 provides the I/O table estimates of the total impact on the parish of the new operating expenditures. **It is estimated that operating the NOPS will generate (1) nearly $3.2 million in new sales for businesses in the parish, (2) almost $2.3 million in new earnings for parish residents, (3) 23 permanent new jobs in the parish, and (4) $79,936 a year in new sales tax collections for the parish treasury**.

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[1] www.nola.gov/revenue-sales-tax/sales-tax/
[2] www.bea.gov

There are two important points to note about the numbers in Table 3. First, unlike the construction benefits documented in Table 2 which will vanish once construction is completed, the benefits in Table 3 are recurring or permanent as long as the NOPS remains operational. Secondly, the sales, earnings and sales tax numbers in Table 3 will tend to grow over time with inflation.

Table 3
Impacts of Operations of the NOPS on Orleans Parish: First Year of Operation

Category	Impacts
New Business Sales	$3,171,918
New Household Earnings	$2,283,881
New Permanent Jobs	23
New Sales Taxes	$79,936

Operational Impacts on Industries in the Parish

Decision-makers may be interested in how the indirect (multiplier) effects of operating the NOPS are allocated among all the industries in the parish. Table 4 provides the I/O table estimates of this distribution.

Table 4
Indirect Impacts of NOPS Operations Spending on
Orleans Parish by Industry: First Year of Operation

Category	Sales	Earnings	Jobs
Agriculture, Forestry, Fishing, and Hunting	$0	$0	0

Mining	$37,444	$2,286	0
Utilities	$35,576	$2,449	0
Construction	$906,377	$126,320	2
Durable Goods Manufacturing	$45,455	$2,445	0
Nondurable Goods Manufacturing	$359,239	$21,844	0
Wholesale Trade	$68,809	$8,446	0
Retail Trade	$172,393	$29,960	1
Transportation and Warehousing	$63,808	$7,196	0
Information	$43,143	$5,193	0
Finance and Insurance	$188,978	$20,190	1
Real Estate and Rental and Leasing	$363,299	$32,470	1
Professional, Scientific, and Technical Services	$115,289	$26,102	0
Management of Companies and Enterprises	$31,278	$5,062	0
Administrative and Waste Management Services	$50,075	$9,830	0
Educational Services	$39,360	$10,991	0
Health Care and Social Assistance	$204,725	$41,358	1
Arts, Entertainment, and Recreation	$27,046	$5,257	0
Accommodation	$34,274	$5,474	0
Food Services and Drinking Places	$85,857	$16,523	1
Other Services	$299,662	$47,336	1
Households	$0	$1,824	0
Total	**$3,172,085**	**$428,557**	**11**

The industry that gains the most sales increase from the operation of the power station is the construction sector. Companies in this sector should see their sales increase by $906,377 due to the NOPS operations. Companies in two other industries should see their sales increase in excess of $300,000: (1) real estate/rentals/leasing ($363,299) and (2) nondurable goods manufacturing ($359,239). Companies in five other sectors should receive sales boosts in excess of $100,000.

Note in column two of Table 4 that it will be workers in the construction industry will receive the largest increase in household earnings ($126,320), followed by workers in the other services sector ($47,336) and healthcare ($41,358). Eleven jobs will be created via the multiplier effect.

IV. Impact of NOPS Capital & Operational Spending on Louisiana

In this section of the report, the impact of both constructing and operating the new NOPS on the state economy is examined. Note that all the impact results should be larger than in the case of the parish impacts, because the economic “pond” into which this new unit will be dropped is much larger.

Impact of Constructing the NOPS on Louisiana

Table 5 contains the I/O table estimates of the impact of constructing the new NOPS on the Louisiana economy. Again, these numbers are noticeably larger than those in Table 2 because the economic pond is now larger and the ripple effects of the spending reaches further into the economy.

Over the 6-year construction cycle it is estimated construction of the NOPS will create (1) over $304.3 million in new sales at businesses in Louisiana, (2) nearly $102.5 million in household earnings for citizens of the state, and (3) an average of 351 jobs a year. Impacts are the greatest in the years of the largest construction spending---2017-19. In the year of the largest spending (2018), construction spending at the site will generate (1) nearly $166.4 million in new business sales, (2) over $56 million in new household earnings, and (3) 1,153 jobs.

Table 5
Impacts of Constructing the NOPS on the Louisiana Economy

Years	Sales	Earnings	Jobs	Taxes
2015	$3,176,480	$1,069,760	23	$74,883
2016	$5,955,900	$2,005,800	42	$140,406
2017	$49,036,910	$16,514,420	343	$1,156,009
2018	$166,368,140	$56,028,680	1,153	$3,922,008

2019	$79,412,000	$26,744,000	545	$1,872,080
2020	$397,060	$133,720	3	$9,360
Total	**$304,346,490**	**$102,496,380**	**351**	**$7,174,747**

The last column of Table 5 provides estimates of the impact of building this plant on state revenues. Officials with Louisiana's Legislative Fiscal Office have estimated that for every new dollar of earnings generated in the state, the treasury collects seven cents in sales taxes, income taxes, gasoline taxes and other fees. The numbers in the last column of Table 5 are produced by multiplying the earnings figures in column two by 7%. Using this calculus, it is estimated that **over the 6-year construction cycle, $7,174,747 in new revenues will be generated for the state treasury**.

Impacts of Operating the NOPS on the Louisiana Economy

The benefits to the state from the construction of the NOPS project are temporary as shown in Table 5. That is, as soon as construction is completed, these benefits go away. This is not the case for the benefits from operating the plant, which are shown in Table 6. As long as the plant remains operational, the benefits shown in Table 6 below will accrue to Louisiana. In fact, the sales, earnings and tax benefits are very likely to grow with inflation.

Table 6
Impacts of Operating the NOPS on the Louisiana Economy

Category	**Impacts**
New Business Sales	$4,703,366
New Household Earnings	$3,313,161
New Permanent Jobs	46
Taxes	$231,921

According to the I/O table **operation of the new NOPS facility will annually support (1) over $4.7 million in new sales at businesses in the state, (2) over $3.3 million in new household earnings for state citizens, (3) 46 new jobs, and (4) $231,921 in new revenues for the state treasury.** The 46 new jobs in the state implies a job multiplier of 3.8 (46 total jobs divided by 12 direct jobs at the NOPS). That is, for every new job created at the facility, another 2.8 jobs are created elsewhere in Louisiana via the multiplier effect.

Operations Impacts across Industries in Louisiana

Readers may be interested in learning in which industries are these multiplier effects concentrated. Table 7 provides estimates from the Louisiana I/O table. The biggest **sales** increases are projected for companies in the construction sector ($929,688) followed by companies in the nondurable goods manufacturing sector ($630,114) and healthcare ($417,649). companies in 11 other sectors in the Louisiana economy should see their sales increase by over $100,000 as a result of the NOPS facility.

Table 7
Indirect Impacts of Operating the NOPS
on Louisiana by Industry: 2021

Category	Sales	Earnings	Jobs
Agriculture, Forestry, Fishing, and Hunting	$26,495	$6,596	0
Mining	$78,347	$13,451	0
Utilities	$108,741	$16,622	0
Construction	$929,688	$358,028	6
Durable Goods Manufacturing	$165,736	$33,606	1
Nondurable Goods Manufacturing	$630,114	$96,659	1
Wholesale Trade	$200,184	$63,406	1

Retail Trade	$377,188	$135,146	5
Transportation and Warehousing	$153,120	$46,729	1
Information	$103,845	$22,397	0
Finance and Insurance	$207,048	$54,052	1
Real Estate and Rental and Leasing	$390,855	$65,490	3
Professional, Scientific, and Technical Services	$147,265	$66,112	1
Management of Companies and Enterprises	$47,639	$20,015	0
Administrative and Waste Management Services	$85,388	$37,026	1
Educational Services	$49,327	$23,107	1
Health Care and Social Assistance	$417,649	$191,407	4
Arts, Entertainment, and Recreation	$38,042	$11,424	0
Accommodation	$49,724	$14,000	0
Food Services and Drinking Places	$134,497	$43,687	2
Other Services	$362,293	$134,243	4
Households	$0	$4,679	0
Total	**$4,703,185**	**$1,457,881**	**34**

When it comes to **household earnings**, it is workers in the construction sector that have the most to gain---$358,028. Over $100,000 in new earnings will be enjoyed by workers in healthcare ($191,407), retail trade ($135,146), and other services ($134,243). Thirty-four **jobs** are created via the multiplier effect (Table 7).

V. Summary & Conclusions

Entergy New Orleans, Inc. ("ENOI") plans to construct a new simple cycle power plant called the New Orleans Power Station (NOPS) that will be located within the boundary of the property on which the existing Michoud Generating Plant in New Orleans, Louisiana. The company is proposing to install one MHI 501GAC-FAST "G" Class gas Combustion Turbine Generator (CTG) in a simple Cycle Gas Turbine (SCGT) configuration. This plant will use natural gas as its sole fuel source. The NOPS has a predicted output capacity of a nominal 246 megawatt (MW). The gas turbine will be connected to the existing 115 kilovolt (KV) switchyard at the site. This state-of-the-art technology offers multiple environmental benefits, while also offering the economic benefits of a high fuel-use efficiency rate.

The purpose of this report is to estimate the impact of constructing and then operating this new plant on the (1) Orleans Parish and (2) State of Louisiana economies. Our findings can be summarized as follows:

The impacts of spending $153.3 million in-state to **construct** the NOPS over the six years from 2015 to 2020 are:

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    - $982,749 in new sales tax collections for the parish treasury.
- Impacts on the **Louisiana** economy:
    - $304,346,490 in new sales at companies in the state;
    - $102,496,380 in new earnings for state residents;
    - An average of 351 jobs a year in the state, and;
    - $7,174,747 in new revenue collections for the state treasury.

Table E-1 summarizes the annual impacts on the parish and state economies of **operating** this plant once it is built. While the construction impacts bulleted above are temporary and vanish once construction ends, the impacts in Table E-1 are on-going and indeed, will likely grow over time due to inflation.

Table E-1
Impacts of Operating the NOPS on the Orleans Parish & Louisiana Economies

Category	Orleans Parish Impacts	State Impacts
New Business Sales	$3,171,918	$4,703,366
New Household Earnings	$2,283,881	$3,313,161
New Permanent Jobs	23	46
Taxes	$79,936	$231,921

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW	**)**	
ORLEANS, INC. FOR APPROVAL TO	**)**	
CONSTRUCT NEW ORLEANS POWER	**)**	**DOCKET NO. UD-16-________**
STATION AND REQUEST FOR COST	**)**	
RECOVERY AND TIMELY RELIEF	**)**	

DIRECT TESTIMONY

OF

ORLANDO TODD

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE AND CURRENT BUSINESS ADDRESS.

A. My name is Orlando Todd. My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

Q2. WHAT ARE YOUR CURRENT DUTIES?

A. I am employed by Entergy Services, Inc. ("ESI")[1], as Finance Director for Entergy New Orleans, Inc. ("ENO" or the "Company"). In that capacity, I am responsible for financial management, financial planning and monitoring, and assisting in the resolution of regulatory issues for ENO.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of ENO.

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a B.B.A. in Accounting from Southern Arkansas University and an M.B.A. from the University of Arkansas - Little Rock. I am a Certified Public Accountant. I began my career with Entergy Corporation and its subsidiaries in 1983. I started in Property Accounting and have worked in other departments, including General

[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), ENO, and Entergy Texas, Inc. ("ETI").

Accounting, Finance Operations Center, and Corporate Reporting. Prior to my career with the Entergy System, I worked for Price Waterhouse (now known as PricewaterhouseCoopers).

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the following items related to the New Orleans Power Station (the "Project" or "NOPS"), which is proposed to be constructed at the existing Michoud site located in an industrial area on the eastern edge of New Orleans: the estimated first-year revenue requirement associated with the Project and the proposed cost recovery plan for the costs associated with the Project, including the need for timely cost recovery.

Q6. BRIEFLY DESCRIBE THE PROJECT.

A. NOPS will be an advanced gas combustion turbine ("CT") with a nominal size of 226 MW at the Michoud facility in New Orleans, Louisiana. NOPS is expected to enter service in the second half of 2019.

II. ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT

Q7. PLEASE PROVIDE AN OVERVIEW OF THE INCREMENTAL COSTS AND REVENUES ASSOCIATED WITH THE PROJECT.

A. For purposes of my testimony, the incremental costs associated with the Project fall within three broad categories: (1) non-fuel costs, such as operations and maintenance expense ("O&M") and capital investment, that is, the cost to construct the Project; (2)

Long-Term Service Agreement ("LTSA") expenses; and (3) fuel expense and any revenue or expense resulting from MISO market settlements. In this section, I discuss the first category, non-fuel costs, and present the estimated first-year non-fuel revenue requirement. The latter two categories are discussed in Section III of my testimony.

Q8. WHAT ITEMS ARE INCLUDED IN THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT?

A. The estimated first-year non-fuel revenue requirement consists of two main components and is presented in Exhibit OT-1. One component of the revenue requirement is the estimated return on the total costs to construct the Project, which requires a calculation of the incremental rate base for the Project and the Company's weighted average cost of capital ("WACC").

The total costs to construct include the construction-related carrying costs associated with the Project. Construction-related carrying costs consist of the interest requirements associated with debt financing of the project as well as the return requirement associated with equity financing of the project and are as much a part of the cost of a construction project as is the cost of major equipment, labor and materials. These costs are commonly referred to as the Allowance for Funds Used During Construction ("AFUDC"). The FERC Uniform System of Accounts requires AFUDC to be included in the cost of plant and prescribes the calculation of AFUDC.

Q9. WHAT IS THE OTHER COMPONENT OF THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT?

A. The other component of the revenue requirement is the estimated non-fuel operating expenses during the first-year of operation. These estimated expenses include O&M expense (including labor and all labor-related expenses), general plant operation expenses (including auxiliary power service), and routine maintenance expenses. The estimated operating expenses also include any incremental property taxes directly attributable to the Project, insurance expense, and depreciation expense.

Q10. HOW WAS THE ESTIMATED RATE BASE FOR THE PROJECT DETERMINED?

A. The first step in this process is the derivation of the rate base for the Project during the first year of service, which is derived on Page 2 of Exhibit OT-1. As may be seen, the starting point is the estimated total construction cost including AFUDC of $216.0 million, which is discussed by Company witness Jonathan E. Long. This value constitutes the plant in service amount on the first day of operation. During the first year of operation, depreciation expense at the rate of 3.3% per year will be accrued in the amount of $7.2 million, giving rise to an accumulated reserve for depreciation in that amount. The final component of rate base is the deduction for accumulated deferred income taxes ("ADIT"), which arises due to timing differences between book straight-line depreciation and accelerated tax depreciation. The end result is a total Project rate base of $184.4 million at the end of the first year following commercial operation.

Q11. WHY DID ENO USE A DEPRECIATION RATE OF 3.3% FOR THE ESTIMATED REVENUE REQUIREMENT?

A. The Direct Testimony of Company witness Mr. Seth E. Cureington contains the basis for the 3.3% depreciation rate used for the Project. ENO proposes to use this depreciation rate until rates can be examined in connection the next full base rate case after the Project is placed in service.

Q12. PLEASE DESCRIBE THE CALCULATION OF THE COMPANY'S WACC USED IN THE ESTIMATED FIRST YEAR REVENUE REQUIREMENT.

A. For purposes of estimating the first-year revenue requirement associated with the Project, the Company developed a WACC that contains some elements that are likely to be reflected in the Company's expected WACC when the Project commences commercial operation in 2019. The Company assumed that ENO would have a capital structure that has no more than 50% equity during the first year of commercial of operation of the Project. For the estimated cost of debt, ENO used its projected cost of debt as of June 30, 2016, [redacted]. The calculation of the Company's WACC is shown on Page 3 of Exhibit OT-1. For the estimated return on equity, ENO used the 11.1% electric return on equity authorized by the Council in connection with its last rate case and used throughout the term of ENO's most recent formula rate plan, for which the last Evaluation Period was calendar year 2011.

As discussed later in my testimony, ENO intends to use its WACC, including its actual capital structure, at the time the Project commences commercial operation for interim cost recovery purposes.

Q13. WHAT IS THE BASIS FOR THE ESTIMATED O&M SHOWN IN EXHIBIT OT-1?

A. The basis of the estimated O&M is the estimate described by Mr. Robert A. Breedlove in his Direct Testimony. The estimated O&M used in the first year non-fuel revenue requirement does not include the LTSA expenses, which are discussed later in my testimony.

Q14. HOW WERE PROPERTY TAX AND INSURANCE EXPENSE ESTIMATED?

A. For the first-year revenue requirement, property taxes were assumed to be zero because the Project would be subject to a property-tax exemption. The Company expects to incur incremental insurance expense associated with the Project based on information provided by the Company's insurance broker.

Q15. PLEASE SUMMARIZE THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT FOR THE PROJECT.

A. The estimated first-year non-fuel revenue requirement for the Project is $32.0 million. This estimated amount assumes the construction cost of the Project, including AFUDC, totals $216.0 million.

III. PROPOSED COST RECOVERY PLAN

Q16. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss how the Company proposes to recover the costs associated with the Project, including the non-fuel revenue requirement, fuel and MISO market settlement expenses, and LTSA expenses, and return to customers any MISO market settlement revenues.

Q17. WHAT ARE THE COMPANY'S REGULATORY ASSUMPTIONS FOR WHEN THE PROJECT BEGINS COMMERCIAL OPERATION?

A. ENO expects the Project to commence commercial operation during the second half of 2019. At that time, the Company expects the Combined Rate Case described in Paragraph 8 of the Algiers Transaction Agreement in Principle approved in Council Resolution R-15-194, dated May 14, 2015, to be complete and all of ENO's customers to be subject to a single set of Council-approved base rates and riders.[2] As a result of that proceeding, the Company further expects that the recovery of the capacity costs associated with the Ninemile 6 Unit and associated with Union Power Station Power Block 1 will be realigned from the Purchased Power and Capacity Acquisition Cost Recovery Rider ("PPCACR Rider") to base rates. Finally, the Company expects that ENO will be subject to a formula rate plan ("FRP") following

[2] Currently, the Company serves electric customers in the Fifteenth Ward of the City of New Orleans, that is, Algiers, using base rates approved in Council Docket No. UD-13-01, when Entergy Louisiana, LLC served these customers. The Company serves electric customers outside of Algiers using base rates resulting from Council Docket UD-08-03 and subsequent formula rate plan proceedings.

the Combined Rate Case. These are the principal regulatory assumptions that are the context for ENO's proposed cost recovery plan.

Q18. HOW DOES THE COMPANY PROPOSE TO RECOVER THE NON-FUEL REVENUE REQUIREMENT ASSOCIATED WITH THE PROJECT?

A. ENO proposes that the non-fuel revenue requirement associated with the Project initially be recovered contemporaneous with commercial operation of the Project through the PPCACR Rider, which would be modified for such purpose, or a similar exact cost recovery rider. This rider would use the Company's WACC, including its actual capital structure, at the time the Project commences commercial operation to determine the return on the Company's investment in the Project, and the return on equity resulting from the Combined Rate Case. The non-fuel revenue requirement would be recovered from all of the Company's customers, including Algiers customers, which today do not pay charges pursuant to the PPCACR Rider.

In the next FRP proceeding commencing in 2020, the Project's non-fuel revenue requirement would be realigned so as to be recovered through the FRP Rate Adjustment but outside the FRP bandwidth formula. In the 2021 FRP proceeding, the Project's associated revenues and non-fuel revenue requirement would be included in the FRP bandwidth formula and recovered through the FRP Rate Adjustment.

Q19. IS IT IMPORTANT TO ENO'S FINANCIAL CONDITION THAT ENO RECEIVES TIMELY RECOVERY OF THE PROJECT'S NON-FUEL REVENUE REQUIREMENT?

A. Yes. Once the Project commences commercial operation, ENO will begin incurring expenses related to the Project that are not expected to be reflected in ENO's base rates at the time. If the Council takes no action to address these expenses, then those expenses will have an adverse effect on ENO's financial conditions.

For example, assuming an October 2019 commercial operation date for the Project, ENO will begin to incur depreciation and O&M expenses related to the Project in October 2019. Without timely rate recovery, *i.e.*, contemporaneous rate recovery, ENO will not begin to recover any depreciation and O&M expenses until the next rate change, which under an assumed FRP may not be until the third quarter of 2020. Similarly, the Company would not be recovering any return on the Project during this same period. This approximate twelve-month delay in recovery would have a detrimental effect on ENO's financial condition.

Q20. WILL THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT BE UPDATED PRIOR TO COMMERCIAL OPERATION?

A. Yes. The Company proposes that the estimated first-year non-fuel revenue requirement be updated and a revised PPCACR Rider or a similar exact cost recovery rider be filed with the Council on or about sixty days prior to the anticipated start of commercial operation.

Q21. WHAT IF THERE IS NO FRP IN PLACE AFTER THE COMBINED RATE CASE?

A. ENO proposes that the Project's non-fuel revenue requirement be recovered through the PPCACR Rider or a similar exact cost recovery rider until such time that ENO's base rates are reset.

Q22. HOW DOES ENO PROPOSE TO RECOVER THE EXPENSES ASSOCIATED WITH THE LTSA?

A. ENO proposes that the LTSA expenses be recovered through the fuel adjustment clause ("FAC"). The LTSA is described by Company witness Mr. Breedlove in his Direct Testimony. As explained therein, the LTSA will require payment for certain major maintenance activities, with such payments varying based on the utilization of the Project, including the number of unit starts and hours of run-time. The variable nature of these expenses makes them appropriate for recovery through the Company's FAC. FAC recovery is appropriate as it will ensure that customers pay the actual LTSA costs when such costs are actually incurred. Recovering these costs through base rates gives rise to the possibility that the Company would recover amounts greater or less than the actual costs incurred.

Q23. TODAY, ARE ANY LTSA EXPENSES ASSOCIATED WITH OTHER UNITS BEING INCLUDED IN ENO'S FAC?

A. Yes, LTSA expenses associated with the Nine Mile 6 Unit and Union Power Station Power Block 1 are recovered through ENO's FAC, as stated in the PPCACR Rider.

Such recovery is not precedential, and the Company must receive the Council's express authorization to include NOPS LTSA expenses in the FAC prior to doing so.

Q24. IF ANY MAINTENANCE COSTS ARE INCURRED ON A NON-VARIABLE OR TRANSACTIONAL BASIS, IS ENO PROPOSING TO RECOVER SUCH EXPENSES THROUGH THE FAC?

A. No. As explained by Mr. Breedlove, the LTSA is expected to set forth a base scope of work for certain major maintenance activity and pricing therefor. Any fees for maintenance outside of that base scope of work such as extra work or unplanned maintenance above a cap in the LTSA, would require negotiation of a separate contract or work order. Such maintenance costs incurred outside the base scope of the LTSA would be recovered through base rates.

Q25. WHAT OTHER REVENUES AND EXPENSES ASSOCIATED WITH THE PROJECT SHOULD BE INCLUDED IN THE FAC?

A. The MISO market settlement revenues and expenses associated with the Project, except those falling in the Administration accounting category, should be included in the Company's FAC. Any revenues or expenses falling in the Administration accounting category would be recovered through ENO's MISO Cost Recovery Rider. This treatment is consistent with the Council-approved treatment of those MISO market settlement revenues and expenses attributable to other ENO resources.

Q26. WILL THE ENVIRONMENTAL ADJUSTMENT CLAUSE ("EAC") INCLUDE EXPENSES ASSOCIATED WITH THE PROJECT?

A. It may, if emission allowances are required to operate the Project.

Q27. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **ORLANDO TODD**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Orlando Todd

Orlando Todd

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 13th DAY OF JUNE, 2016

NOTARY PUBLIC

My commission expires: at death

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT OT-1

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-_____**

DIRECT TESTIMONY

OF

SETH E. CUREINGTON

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

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EXHIBITS

I. INTRODUCTION AND PURPOSE

A. Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Seth E. Cureington. My business address is 1600 Perdido St., New Orleans, Louisiana 70112.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy New Orleans, Inc., ("ENO" or the "Company") as Director, Resource Planning and Market Operations. In that capacity, among other activities, I provide resource planning services to ENO.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am filing this Direct Testimony before the Council of the City of New Orleans (the "Council") on behalf of ENO.

Q4. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, RESOURCE PLANNING AND MARKET OPERATIONS?

A. As Director of ENO's Resource Planning and Market Operations department, I am responsible for providing oversight to all of ENO's integrated resource planning efforts, implementation plans, as well as market operations in the Midcontinent Independent System Operator, Inc. ("MISO") regional transmission organization ("RTO"). I also serve as the Chairman of the Entergy New Orleans Operating Committee.

Q5. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in 2001 and a Master of Science in Economics in 2004 from Louisiana State University.

I began my career with Entergy Services, Inc. ("ESI")[1] as a Senior Analyst with the System Planning and Operations ("SPO") organization in 2006, where I was responsible for providing technical and analytical support for a wide range of commercial and supply procurement activities for the EOCs. I remained with SPO for the following six years, during which time I was promoted to the role of Senior Wholesale Executive with the Commercial Operations Group where I was responsible for leading the technical and commercial evaluation of all long-term generation supply opportunities in support of the EOCs' portfolio transformation initiative. In 2011, I joined ENO's Regulatory Affairs organization as Manager, Resource Planning where I was responsible for providing oversight to the development of ENO's integrated resource plans and providing guidance and analytical support to ENO's Regulatory Affairs group with respect to the integrated resource planning process. In 2013, my responsibilities were expanded to include oversight of market operations MISO, and in June 2016 I was promoted to Director, Resource Planning and Market Operations.

[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), ENO, and Entergy Texas, Inc. ("ETI").

Q6. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE COUNCIL?

A. Yes. I have attached as Exhibit SEC-1 a listing of my prior testimony before the Council.

B. Purpose and Summary of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the Company in support of its Application for approval to construct the New Orleans Power Station, a 226 MW combustion turbine ("CT") generating unit to be located at the Company's Michoud generating facility in New Orleans, Louisiana ("NOPS").

Q8. PLEASE PROVIDE A BRIEF OVERVIEW OF THE REASONS FOR PROPOSING NOPS.

A. Recent unit deactivations (which were economic decisions based on maintenance and other operational issues) have left the Company short of both its overall long-term capacity needs and its long-term peaking and reserve capacity needs. The deactivated units (ENO's Michoud Units 2 and 3) provided a significant source of local generating capacity within the Company's service area (*i.e.*, Orleans Parish) in support of reliable operations and mitigated supply- and market-related risks. As discussed more fully below, going forward, the Company is proposing NOPS to address these and other long-term needs.

NOPS is proposed to be located in Orleans Parish, which complies with the Council's prior directive to use reasonable diligent efforts to site a generating resource within Orleans Parish. Moreover, as also discussed more fully below, while the Company continues to support the addition of cost effective demand-side management ("DSM") programs[2] and renewable resources to its portfolio, neither offer a cost-effective or lower-risk alternative sufficient to obviate the need for NOPS. In addition, deferring the timely deployment of new peaking and reserve capacity resources and instead relying on the MISO capacity market to meet long-term capacity needs will expose the Company's customers to increased cost and risk. For these reasons, the Company requests that the Council approve the construction of NOPS.

Q9. PLEASE ELABORATE ON THE COMPANY'S LONG-TERM CAPACITY NEEDS.

A. The recent deactivation of Michoud Units 2 and 3 resulted in the loss of approximately 781 MW of local capacity (which is approximately [redacted] of ENO's 2016 forecasted non-coincident peak load). As a result, ENO has an overall long-term need for capacity as well as a long-term need for local peaking and reserve capacity resources. While the acquisition of Power Block 1 of the Union Power Station ("Power Block 1") helped to offset a substantial portion of ENO's overall capacity needs (including baseload and load-following needs), the Company has an

[2] The term DSM includes both energy efficiency and demand response programs. For example, ENO currently operates Energy Smart, which is a comprehensive energy efficiency program that provides incentives for energy efficient measures, including energy audits, direct install CFL bulbs, low flow fixtures, weatherization, HVAC and A/C tune-ups, and lighting. Demand response programs typically are designed to reduce demand during peak hours. An example would be a thermostat that can turn off air conditioning in response to commands from the utility.

overall remaining long-term capacity need of approximately 124 MW in 2016 and up to 205 MW by 2030. Moreover, current projections show that ENO has an existing long-term need for approximately 288 MW of peaking and 118 MW of reserve capacity resources in 2016, which need is expected to persist throughout the planning horizon absent the addition of new resources capable of meeting those needs. Prior to deactivation, Michoud Units 2 and 3 helped meet a portion of those needs by providing the Company's only source of local capacity within its service area (*i.e.*, Orleans Parish).

Q10. HAVE THE COMPANY'S EXISTING DSM AND RENEWABLE RESOURCES BEEN TAKEN INTO CONSIDERATION IN ESTABLISHING THE IDENTIFIED LONG-TERM NEEDS?

A. Yes. The Company's existing portfolio of DSM and renewable resources has been accounted for and do not obviate the need for NOPS. The Energy Smart energy efficiency programs, which are currently in year five, have reduced the Company's annual peak load for the east bank of Orleans Parish by an estimated 16.5 MW. For the Energy Smart programs in Algiers, annual peak load has been reduced by an estimated 1.1 MW.

The Company also accounted for the current level of behind-the-meter ("BTM") residential rooftop solar within the Company's service area when determining its long-term need, which reduced the Company's 2015 peak load by approximately 14 MW. The projected effects of Energy Smart and BTM rooftop solar on the Company's peak demand are factored into the peak load forecast, as discussed more fully below.

Q11. WOULD INCREASED INVESTMENT IN DSM OR RENEWABLE RESOURCES PROVIDE AN ECONOMIC ALTERNATIVE TO NOPS?

A. No. Regarding DSM resources, insufficient cost-effective incremental DSM programs beyond the Company's currently approved Energy Smart programs have been identified to meet the entirety of the Company's long-term needs. The Company engaged ICF International ("ICF") to conduct an analysis of the long-term DSM potential achievable in New Orleans. Based on the results of ICF's study, the Company concludes that the achievable amount of DSM in New Orleans constitutes only approximately 13% of ENO's need for long-term peaking and reserve capacity by 2019.

Renewable resources such as wind and solar photovoltaics ("PV") are intermittent because they rely on the wind and sun to produce energy, thus limiting the ability to rely on them to meet customer demand and their ability to be counted on to meet peak demand. It should also be noted that because they are intermittent, the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs. Thus, even if these intermittent resources could meet the Company's long-term need for incremental peaking/revenue capacity (which they cannot), the Company would need to acquire significantly more capacity than its need dictates due to their lower capacity credit. Moreover, to emphasize such capacity would not meet ENO's specific supply role need for peaking and reserve capacity.

Q12. COULD ENO DEPEND ON MISO'S CAPACITY MARKET AS AN ALTERNATIVE TO NOPS?

A. No. As I discuss further in Section III, ENO's planning assumption is that market equilibrium (where supply, including third party resources, and demand balance) in MISO South will occur around 2022. As market equilibrium approaches, capacity prices will reflect new build prices, which are significantly higher than today's capacity prices. Deferring construction of a new resource comes with considerable risk considering the long lead time necessary to gain regulatory approval of, plan, permit, and construct new resources; potential cost premiums for parts and equipment as other utilities are simultaneously shifting to modern, gas-fired resources; and expected sharply higher and more volatile capacity prices as the capacity market approaches equilibrium. Indeed, as discussed below, one need look no further than the MISO RTO, in which ENO is a Load Serving Entity ("LSE"), for a recent example of a capacity shortage leading a 20-fold increase in capacity prices from one year to the next.

Q13. WHAT OTHER CIRCUMSTANCES SUPPORT THE COMPANY'S NOPS PROPOSAL?

A. NOPS will provide a modern, cost-effective and local source of generating capacity capable of meeting ENO's long-term overall capacity needs as well as a significant portion of its peaking and reserve supply role capacity needs. NOPS will improve supply conditions in the Company's service area by providing a long-term resource capable of supporting reliable service to New Orleans during periods of peak demand and unplanned events, and it will mitigate market and supply related risks, particularly as equilibrium in the capacity market approaches. NOPS is also consistent with ENO's load shape, which supports post-System Agreement operations when ENO must plan to meet its individual resource needs without reference to the System planning perspective. NOPS will also provide a highly-reliable quick-start generation resource in New Orleans to support timely severe weather restoration efforts.

Q14. IS THE APPLICATION TO CONSTRUCT NOPS CONSISTENT WITH THE COMPANY'S FINAL 2015 INTEGRATED RESOURCE PLAN ("IRP")?

A. Yes. The Company's Final 2015 IRP was filed on February 1, 2016, in Docket No. UD-08-02.[3] Pursuant to the Council's IRP requirements, the process to develop the 2015 IRP began in June 2014 with a series of public technical conferences to solicit input from stakeholders and inform development of the IRP. The Final 2015 IRP reflects a thorough consideration, and in certain cases additional modeling and analysis, of the issues raised through the stakeholder process, and it concluded by identifying a Preferred Portfolio for meeting customers' long-term needs at the lowest reasonable cost, while considering reliability and risk. The IRP identified an overall

[3] *See* ENO Final 2015 IRP, February 1, 2016, attached here to as Exhibit SEC-7.

long-term need for capacity as well as a need for long-term peaking and reserve resources.

During development of the 2015 IRP, the Company conducted a DSM Potential Study, Generation Technology Assessment, and Portfolio Evaluation, which thoroughly evaluated a range of viable supply and demand-side resource alternatives capable of meeting those needs. The Preferred Portfolio includes cost-effective incremental DSM resources identified through the IRP process, however; the IRP established a remaining need for peaking and reserve capacity. The results of the Final 2015 IRP support the conclusion that a large G Frame CT resource such as NOPS is the lowest reasonable cost resource addition capable of meeting the Company's remaining overall long-term capacity needs (including the target planning reserve margin ("PRM") of 12%), and a substantial portion of the identified long-term peaking and reserve capacity need.

Q15. WHAT DOES YOUR TESTIMONY AND ANALYSIS OF THE COMPANY'S LONG-TERM RESOURCE NEEDS ASSUME WITH RESPECT TO THE COMPANY'S PARTICIPATION IN THE ENTERGY SYSTEM AGREEMENT ("ESA")?

A. ENO's participation, along with all of the other remaining EOCs that are participating in the ESA, will terminate on August 31, 2016. Accordingly, my testimony and analysis of ENO's long-term resource needs reflect a post-ESA planning environment. When the ESA terminates, long-term resource planning for ENO post-termination will focus on meeting the Company's long-term resource needs without reference to the System planning perspective. Importantly, as discussed by Company witness Shauna Lovorn-Marriage, the conditions upon which the Council approved early termination of the ESA included a commitment by the Company to pursue a new generating resource to be located in the Company's service area (*i.e*. Orleans Parish, Louisiana).

II. <u>LONG-TERM RESOURCE PLANNING PROCESS AND NEEDS</u>

A. <u>Planning Process</u>

Q16. WHAT IS THE PURPOSE OF THE COMPANY'S LONG-TERM RESOURCE PLANNING PROCESS?

A. The Company's planning process seeks to accomplish three broad objectives:

- To serve customers' power needs reliably;
- To do so at the lowest reasonable supply cost; and
- To mitigate the effects and the risk of production cost volatility resulting from fuel price and purchased power cost uncertainty, RTO-related charges such as congestion costs, and possible supply disruptions.

The Company's planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk.

Q17. PLEASE EXPLAIN THE CHARACTERISTICS THE COMPANY SEEKS TO ACHIEVE IN A LONG-TERM GENERATION CAPACITY PORTFOLIO.

A. In support of the Company's objective to provide safe and reliable service at the lowest reasonable cost while considering risk, the Company must maintain a portfolio of generation resources that includes an appropriate amount and types of capacity. With respect to the amount of capacity, the Company must maintain sufficient generating capacity to meet its peak load plus a PRM, for which the Company has established a target of 12%. With regard to the types of capacity, the Company seeks to add modern, reliable and cost-effective generating technologies consistent with its load shape. Importantly, these objectives must be considered both individually and collectively in determining an appropriate portfolio design that can achieve the planning objectives.

Q18. PLEASE ELABORATE ON THE COMPANY'S TARGET PRM.

A. For purposes of long-term planning, the Company has determined that a 12% target PRM based on installed capacity ratings and forecasted (non-coincident) firm peak load is appropriate in consideration of its long-term planning objectives and membership in MISO. A PRM is intended to provide a generation supply buffer to maintain reliable service during unplanned events, and to facilitate planned events (*e.g.*, generator or transmission maintenance). The target PRM is intended to address uncertainties such as, but not limited to, the following:

- deviation in customer load from forecast;
- unplanned outage of a major generating unit or transmission element;

- potential variability in MISO Resource Adequacy ("RA") requirements; and
- uncertainty regarding ENO's long-term resource portfolio (*e.g.*, availability of aging legacy gas and coal units sourced through PPAs).

Q19. IS THERE OTHER INDUSTRY DATA SUPPORTING THE CONCLUSION THAT A 12% PRM IS REASONABLE?

A. Yes. MISO has referenced 15% as a generally accepted reserve requirement when assessing the reliable transfer of resources inter-regionally.[4] Further, the Southwest Power Pool requires each control area to maintain a 12% capacity reserve margin, which equates to a 13.6% planning reserve margin. Notably, Indianapolis Power & Light Company ("IPL"), another MISO LSE, appears to have reached similar conclusions regarding MISO's reserve margin and has elected to use a 14% planning reserve margin applied to their non-coincident peak load for their 2014 Integrated Resource Plan, as evidenced by the following excerpt:

> <u>Planning Reserve Margin Modeling</u>
>
> IPL's minimum PRMR established by MISO for 2014 equates to an effective 14.8% reserve margin, representing an increase from 2012 (13.1%) and 2013 (14.2%). As identified above, many factors are used by MISO to establish an LSE's resource adequacy requirement. The LSE's planning reserve margin changes annually as MISO modifies its LOLE analysis and as a result of changes in its EFORd and diversity. IPL's ICAP ratings can also change annually due to the results of unit testing. For Ventyx's long term modeling purposes in this IRP, IPL identified a 14% planning reserve margin to be used consistent with IPL's summer-rated capacity. This long-term modeling number provides for targeted reserves in the range of

[4] Exhibit SEC-2, MISO Overview, NARUC Winter Meeting, February 2015 at slide 10.

> future expected MISO-determined resource needs and is consistent with the MISO specific calculations….[5]

Q20. DID JOINING MISO AFFECT THE WAY THE COMPANY CALCULATES ITS TARGET PRM?

A. Yes. Prior to joining MISO, the Company applied a 16.85% PRM based on a loss of load expectation ("LOLE") calculation for the Entergy System, which focused solely on reliability. Upon joining MISO, the Company sought to identify a PRM that provided a reasonable and stable basis for meeting long-term planning objectives, considering both reliability and the implications of participation in the larger, more diverse MISO market. Accordingly, for purposes of long-term planning the Company adopted a 12% target PRM based on installed capacity ratings and forecasted non-coincident peak load. The 12% target reflects the benefits of participating in a larger, more diverse market while recognizing the differences between MISO's annual process and the Company's long-term planning objectives.

Q21. HAS THE COMPANY PREVIOUSLY TARGETED A 12% PRM TO SUPPORT THE NEED FOR LONG-TERM RESOURCE ADDITIONS?

A. Yes, the Company's 12% target PRM is the same 12% used in establishing the need for, and the Council's subsequent approval of, the Company's share of the new Ninemile 6 CCGT unit in Council Docket UD-11-03, and the acquisition of Power Block 1 at the Union Power Station in Council Docket UD-15-01.

[5] Exhibit SEC-3, Indianapolis Power & Light Company 2014 Integrated Resource Plan, p. 45.

B. Long-Term Resource Needs

Q22. PLEASE DESCRIBE THE COMPANY'S CURRENT RESOURCE PORTFOLIO.

A. As of June 1, 2016, the Company will control approximately 1,162 MW of long-term generating capacity either through ownership or life-of-unit PPAs with affiliate Operating Companies. Table 1 below summarizes the Company's long-term capacity resources by fuel type measured in installed MW. As reflected in Table 1, roughly one-half of the capacity in the Company's existing resource portfolio is from CCGT resources. The bulk of the remaining capacity is from nuclear resources, followed by a small amount of legacy gas,[6] coal, hydro, and CT resources.[7]

Table 1

ENO Installed Capacity (2016)		
Fuel Type	**MW**	**%**
CCGT	647	56%
Nuclear	420	36%
Legacy Gas	59	5%
Coal	33	3%
Hydro	2	0%
CT	1	0%
Total	1,162	100%

[6] Legacy Gas refers to the EOC's natural gas-fired steam turbine generators originally placed in service at various points in time during the 1950s, 1960s and 1970s.

[7] Table 1 excludes Load Modifying Resources, but which are included in the Company's assessment of long-term resource needs shown in Exhibit SEC-4.

Q23. PLEASE DESCRIBE THE COMPANY'S CURRENT LOAD FORECAST.

A. In preparing the load forecast in Exhibit SEC-4, the Company utilized the methodology described in the Final 2015 IRP.[8] Through this process, a peak load forecast was developed that derives from the hourly annual twenty-year load forecast for ENO. The process accounts for existing DSM programs (*e.g.*, Energy Smart) as well as BTM residential rooftop solar PV through indirect and direct reductions to the load forecast. The resulting forecast was then adjusted for both transmission and distribution losses before incorporation into Exhibit SEC-4.

Q24. DOES THE COMPANY NEED ADDITIONAL GENERATING CAPACITY?

A. Yes. After accounting for existing and recently acquired supply and demand-side resources (which includes Energy Smart and BTM rooftop solar), the Company continues to have a need for additional long-term capacity, including a need for peaking and reserve capacity. The Company's long-term need for capacity is driven primarily by the deactivation of Michoud Units 2 and 3, which Power Block 1 helped to offset. To illustrate the Company's needs, I have compared the Company's projected peak load with its portfolio of existing resources. Exhibit SEC-4 provides a Projected Load and Capability analysis that compares the Company's overall planning requirements (based on non-coincident peak load forecast, grossed up for transmission and distribution losses, plus a target PRM of 12%) with the Company's

[8] ENO 2015 IRP at page 43.

existing long-term supply and demand-side resources that it expects to have in its portfolio during the planning horizon (based on installed capacity ratings). The results of the analysis attached as Exhibit SEC-4 provide ENO's projected needs, with and without planned resource additions (*e.g.*, NOPS).

Q25. WHAT DOES THE ANALYSIS INDICATE?

A. Projected load plus the target PRM results in a long-term capacity need that exceeds the Company's existing supply and demand-side resources, which indicate a need to deploy additional long-term resources. As shown in Exhibit SEC-4, the Company projects an overall need for approximately 134 MW of capacity by 2020 and up to 205 MW by 2030. As explained more specifically below, the Company also has a need for long-term local peaking and reserve capacity resources.

Q26. PLEASE ELABORATE ON THE TYPES OF RESOURCES THE COMPANY NEEDS.

A. In conducting long-term resource planning, the Company analyzes not only its overall capacity needs, but also its need for capacity that serves specific supply roles, such as: base load, load following, peaking, and reserve. Having an appropriate amount of capacity suitable to serve each of these supply roles allows the Company to reliably and cost-effectively serve the time-varying level of customer load.

Supply role requirements are considered as general guidelines for portfolio planning purposes and do not necessarily address other planning criteria (*e.g.*, locational considerations). As illustrated in Figure 1 below, the Company defines its base load requirement as the minimum level of load that is served 85% of the hours in a year. Next, the load following requirement is defined as the levels of load that exceed base load but are less than load levels experienced in the highest 15% of the hours of the year (*i.e.*, core load-following and seasonal load-following). The Company's peaking requirement is defined as the level of load that is served in the highest 15% of the hours of the year. Finally, the PRM target is 12% of the peak load and, as described earlier, helps to maintain reliable service over a range of planned and unplanned circumstances.

Figure 1 Highly Sensitive Protected Materials

[redacted]

Each supply resource has its own unique cost and performance characteristics that allow it to be functionally and economically suited to serve a given supply role. Generally, base load resources typically cost more to construct per MW, but operate with relatively low variable cost and, because the resource is expected to operate in most hours at high output levels, the total supply cost is relatively low on a $/MWh basis. Conversely, a peaking or reserve unit is expected to operate at low utilization levels and higher variable costs, but typically has a relatively low capital cost and, therefore, is typically the most economical alternative when utilized in a peaking role. Load following units have moderate capital cost and variable cost.

In order to reliably meet customers' needs at the lowest reasonable cost, the Company must maintain a portfolio of long-term resources that includes an appropriate amount and types of capacity. At this time, the Company has a need for long-term resources, including resources capable of operating in a peaking and reserve role. Table 2 provides the Company's projected capacity surplus or (deficit) overall and across supply role.[9]

Table 2

	2020			2030		
(MW)[10]	**Need**	**Resources**	**Surplus/ (Deficit)**	**Need**	**Resources**	**Surplus/ (Deficit)**
Base Load	554	453	(101)	572	427	(145)
Load Following	338	682	344	342	665	323
Peaking & Reserve	417	40	(377)	422	39	(383)
Total	1,309	1,175	(134)	1,336	1,131	(205)

As shown in Table 2, the Company projects the need for approximately 377 MW of peaking and reserve resources by 2020, which need is expected to grow to

9 The Company's Load Modifying Resources are included in the supply role analysis as Reserve capacity, as shown in Exhibit SEC-4.

10 Figures may not foot as compared to Exhibit SEC-4 due to rounding.

approximately 383 MW near the end of the planning horizon (2030) absent the addition of new resources. Even absent growth in the Company's peak load, the need for peaking and reserve resources driven by the deactivation of Michoud Units 2 and 3 is substantial and exceeds the amount of capacity that would be obtained through the addition of NOPS.

Q27. HOW WILL THE COMPANY MEET ITS LONG-TERM NEED FOR PEAKING AND RESERVE RESOURCES PRIOR TO THE IN-SERVICE DATE FOR NOPS?

A. Based on my assessment of the current and previous MISO Planning Resource Auctions ("PRA") for MISO South, as well as the 2015 OMS Survey, it is reasonable to expect that excess capacity will be available in the PRA through the end the decade. Based on that expectation, the Company plans to meet near-term peaking and reserve capacity and energy needs through the MISO markets until NOPS is constructed.

Q28. HOW DO YOU CONCLUDE THAT CT RESOURCES SUCH AS NOPS ARE BEST SUITED TO MEET THE COMPANY'S LONG-TERM PEAKING AND RESERVE CAPACITY NEEDS?

A. CT resources such as NOPS are the preferred technology to meet current and projected long-term peaking and reserve capacity needs due to their low installed cost and operational flexibility. Because peaking and reserve capacity resources are not expected to operate for extended periods of time, their installed cost is more relevant than operating costs. In addition, during periods of peak demand, generating resources must be able to respond quickly to changing conditions on the electric system in order to maintain reliability by starting on short notice and responding to dispatch signals to quickly ramp up or down. Consistent with the Company's planning objectives, CT resources such as NOPS provide the lowest reasonable cost technology capable of meeting peaking and reserve capacity needs while considering market and supply risks. In Section III below, I discuss in more detail why CT resources such as NOPS are better suited than prospective alternatives to meet the Company's long-term peaking and reserve capacity needs.

Q29. YOU IDENTIFIED A LONG-TERM NEED FOR PEAKING AND RESERVE CAPACITY THAT EXCEEDS THE CAPACITY OF NOPS. PLEASE EXPLAIN WHY THE COMPANY IS NOT PROPOSING ADDITIONAL LONG-TERM RESOURCE ADDITIONS BEYOND NOPS TO MEET THAT NEED.

A. With the addition of NOPS, the Company is projected to meet its overall long-term capacity need as well as a substantial portion of the projected peaking and reserve capacity need. Table 3 provides the effect of NOPS on the Company's long-term capacity needs following the projected in-service date, which reflects a slight overall surplus of capacity through 2030 and a persistent peaking and reserve capacity deficit. When determining how best to meet long-term needs, the Company must consider a range of factors. NOPS is a significant incremental resource addition that will help meet a substantial portion of the Company's long-term need for local peaking and reserve resources. It will also meet the Company's overall long-term capacity needs, including the target PRM.

While the supply role analysis indicates the need for additional peaking and reserve capacity, it also indicates a surplus of load-following capacity. The surplus load-following capacity is primarily driven by the acquisition of Power Block 1, which at current and projected gas prices can also help meet the projected need for baseload resources. In contrast, it would not be appropriate to rely on the surplus load-following capacity associated with Power Block 1 to meet the identified peaking and reserve needs because Power Block 1 is already included in ENO's resource mix and contributes to meeting other supply role needs, and Power Block 1 is outside the Company's service area and does not address the need for local area peaking and reserve capacity to support long-term reliability within the Company's service area. Thus, the results of the supply role analysis must be taken into consideration along with other factors, including the Company's overall long-term needs, market dynamics, and locational considerations. The addition of NOPS strikes the appropriate balance among these considerations. Further, peaking and reserve capacity needs not met by NOPS provides an opportunity to pursue cost-effective DSM, which I discuss in Section III below.

Table 3

	2020			**2030**		
(MW)[11]	**Need**	**Resources w/ NOPS**	**Surplus/ (Deficit)**	**Need**	**Resources w/ NOPS**	**Surplus/ (Deficit)**
Base Load	554	453	(101)	572	427	(145)
Load Following	338	682	344	342	665	323
Peaking &	417	266	(151)	422	265	(157)

11 Figures may not foot as compared to Exhibit SEC-4 due to rounding.

Reserve						
Total	1,309	1,401	92	1,336	1,357	21

Q30. PLEASE ELABORATE ON THE COMPANY'S NEED FOR LOCAL AREA GENERATING CAPACITY.

A. Prior to deactivation, Michoud Units 2 and 3 provided a significant amount of local area capacity because both units were within ENO's service area (*i.e*. Orleans Parish), which is part of the supply-constrained Downstream of Gypsy ("DSG") load pocket. Because the Company's service area is located in a load pocket, the planning process must factor in the ability to maintain reliability during unplanned events like hurricanes, the forced outage of a major transmission element(s) relied upon to import generation to the region, and the forced outage of a large generator(s) within the load pocket that supports local area reliability (*e.g*., Ninemile). Absent the addition of NOPS, ENO will not have any generating capacity within its service area, and it must rely on other generation within the load pocket to maintain local area reliability.

While ENO does receive a long-term allocation of the three remaining generating resources within the load pocket through life-of-unit power purchase agreements (*i.e*., Ninemile units 4, 5 and 6), Ninemile units 4 and 5 are over 40 years old, and all three units are located outside of the Company's service area. Moreover, ENO's existing portfolio relies heavily on resources external to its service area to serve the energy and capacity needs of the Company. Table 4 provides a breakdown of ENO's existing portfolio of generating capacity based on proximity to the

Company's service area and the load pocket more generally.[12] The addition of NOPS to the Company's portfolio would constitute the only generating capacity within Orleans Parish, and will accordingly reduce the reliance on the Ninemile generating facility to maintain local area reliability within Orleans Parish.

Table 4 Highly Sensitive Protected Materials

[redacted]

Q31. PLEASE ELABORATE ON THE RELIABILITY BENEFITS OF LOCAL GENERATION.

A. As explained by Mr. Charles Long, the addition of local generation will help prevent stability problems that are caused by disturbances and faults, supply dynamic reactive power, and dynamically regulate voltage. New local generation will also reduce the Company's reliance on transmission import capability, which is limited by the interface of the transmission elements that connect the load pocket with the rest of the transmission network.

Q32. ARE THERE ADDITIONAL BENEFITS OF LOCAL GENERATION?

A. Yes. Local generation provides the following additional benefits:

- Improves Economics – Local generation reduces transmission losses by locating the source of electricity near the load to be served. Transmission

[12] As of June 1, 2016.

losses can increase during periods of peak demand, providing further support for siting peaking resources near the peak load to be served.

- Mitigates Market Risks – Local generation will mitigate transmission congestion price risk and supply power that can be dispatched at a known heat rate, helping to limit volatility of, and customer's exposure to, locational marginal prices ("LMPs"), which exposure is typically greatest during periods of peak demand. In other words, when there is congestion on the transmission system between generating resources and load, LMPs typically increase. This not only increases the cost of load purchases from MISO, but also increases payments from MISO to generators in the affected area. If ENO faces these higher LMPs in the ENO load zone, the increased LMP revenues received by NOPS act as a hedge to offset the increased cost of load purchases from MISO.
- Reduced Reliance on Transmission Imports – As discussed by Mr. Charles Long, locating new resources near the load to be served will reduce reliance on transmission imports, which in turn can reduce the need for future transmission upgrades necessary to maintain reliability and mitigate congestion.
- Long-term Strategic Benefits – NOPS will provide a modern, cost-effective local source of peaking and reserve capacity that will reduce the Company's reliance on the Ninemile generating plant to maintain reliability in Orleans Parish.

Q33. DO LOCAL RESOURCES PROVIDE BENEFITS DURING STORM RESTORATION?

A. Yes. Having additional local generation will reduce the Company's reliance on transmission assets that may be more likely to be out of service immediately following a severe weather event (*e.g.*, hurricane). For example, as discussed in more detail by Mr. Charles Long, in September 2008, Hurricane Gustav affected all of the transmission lines serving the region, which included the Company's service area, leaving the region "islanded" from the rest of the interconnected transmission grid and, thus, completely reliant on local generation at a critical time. As noted in Table 4 above, the Company relies exclusively on transmission to deliver external resources to its service area, which highlights the need for local generating capacity in the event of a major disruption to the transmission system as a result of a severe weather event such as a hurricane. In other words, having local generation is critical to restoring and maintaining power to customers in New Orleans.

III. PROSPECTIVE ALTERNATIVES

Q34. IS NOPS CONSISTENT WITH THE SUPPLY ROLE NEEDS OF THE COMPANY?

A. Yes. CT resources, such as NOPS, are technologically suited for serving peaking and reserve roles. As discussed by Company witness Jonathan E. Long, NOPS is a modern CT unit capable of being started quickly and ramped to full load within minutes. This capability will support local area reliability and could help facilitate the integration of renewable resources in or near the Company's service area by providing a quick start resource capable of coming online and ramping quickly to address the intermittency associated with renewables. Further, because of the limited expected capacity factor for peaking and reserve resources, CT technology is economically suited to serve in these roles across a range of assumptions regarding key uncertainties (*e.g.*, fuel prices and emissions costs). Consequently, CT resources such as NOPS support the Company's planning objectives and are consistent with supply role needs.

Q35. COULD THE COMPANY'S PEAKING AND RESERVE CAPACITY NEEDS BE SATISFIED WITH RENEWABLE RESOURCES?

A. No. Renewable resources such as wind and solar PV are intermittent because they rely on the wind and sun to produce energy, thus limiting the ability to rely on them to meet customer demand. Moreover, the generating capacity of renewables such as wind and solar PV are a function of the amount of wind and sunlight available at a given time, further limiting their ability to be counted on to meet peak demands. As a result, renewables must be supported by dispatchable resources such as CTs to ensure sufficient resources are available to ramp up and produce replacement energy when the wind is either not blowing or blowing less than projected, and similarly when cloud cover or unexpected weather limits the output of solar PV. Finally, because wind and solar are intermittent, even if it were cost-effective to acquire an amount sufficient to meet the Company's long-term capacity needs, it would not eliminate the need for quick-start and fast ramping dispatchable resources such as NOPS.

Q36. DOES THIS MEAN THAT INTERMITTENT RESOURCES SUCH AS SOLAR PV AND WIND HAVE NO PLACE IN ENO'S SUPPLY PORTFOLIO?

A. Not at all. To the extent there are cost-effective sources of renewable energy available to the Company, they could provide benefits to customers in the form of increased diversity of supply and other environmental attributes. As identified in the Company's Action Plan supporting the Final 2015 IRP,[13] ENO is undertaking an RFP to determine whether there are cost-effective renewable resources available.[14]

Q37. DOES THE INTERMITTENT NATURE OF RENEWABLES SUCH AS SOLAR PV AND WIND AFFECT THE EXTENT TO WHICH THEY CAN BE RELIED UPON TO MEET LONG-TERM CAPACITY NEEDS?

A. Yes. Even if the cost of wind and solar PV were comparable in cost to conventional alternatives, it is reasonable to expect that the total cost to acquire sufficient renewable capacity to meet ENO's overall long-term needs would exceed the cost of conventional alternatives because the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs, precisely because both technologies are intermittent.

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13 ENO 2015 IRP at page 84.

14 On May 6, 2016 ESI issued a draft request for proposals for renewable generation resources. The RFP will facilitate a market test of the extent, and cost of, renewable resources available to provide benefits in excess of cost to the Company's customers. More information on the Draft RFP can be found on the ESI RFP Website located at: https://spofossil.entergy.com/ENTRFP/SEND/2016ENOIRenewableRFP/Index.htm.

Q38. HOW DOES MISO ACCOUNT FOR THE INTERMITTENCY OF RENEWABLE RESOURCES THROUGH THE RESOURCE ADEQUACY PROCESS?

A. Because wind and solar are intermittent, MISO grants those resources less capacity credit in the RA process. For the 2016/2017 Planning Year, MISO granted a 15.6%[15] capacity credit to wind resources and 50%[16] capacity credit to solar PV resources (during the first year of solar PV operation subject to verification with operational data). Thus, reliance on renewable resources alone to meet MISO's RA requirements would require the Company to invest in significantly more renewable resource capacity than its capacity need would otherwise support.

Q39. WILL NOPS PRECLUDE THE COMPANY'S ABILITY TO INCORPORATE RENEWABLE RESOURCES INTO FUTURE RESOURCE PLANS?

A. No. As indicated in Table 1, the Company's existing portfolio includes aging legacy gas and coal generating resources. As those units are deactivated based on their own economic merits, there will be room in the portfolio for new resource additions, creating opportunity for cost-effective renewable energy resources such as wind and solar PV. Moreover, because the cost and performance of solar PV (and to a lesser extent wind) is expected to continue to improve, deferring the addition of those resources could increase the benefits to customers.

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15 https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf.

16 https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2015/20150930/20150930%20LOLEWG-SAWG%20Joint%20Meeting%20Item%2003%20Solar%20Capacity%20Credit.pdf.

Q40. CAN THE COMPANY'S PEAKING AND RESERVE RESOURCE NEEDS BE MET THROUGH UTILITY-SPONSORED DSM PROGRAMS?

No. Insufficient achievable DSM resources are available to meet the Company's peak capacity needs. The need for peaking capacity identified in Table 2 is driven primarily by the deactivation of Michoud Units 2 and 3, which need is expected to persist absent the addition of new peaking resources. DSM programs offer opportunities to offset some level of long-term capacity needs, but not enough to meet the entirety of ENO's long-term needs.

Moreover, DSM programs capable of reducing peak capacity requirements must be designed and properly administered through the development of detailed implementation plans that involve customer education and outreach in order to facilitate participation, and they require that appropriate cost recovery and incentive mechanisms be approved by the Council, all of which extend the timeframe for achieving desired results. Moreover, industry experience has shown that customer subscription to demand response programs must significantly exceed the target demand reduction (*i.e.*, oversubscribe participants to the program) in order to achieve the desired results due in large part to the inability to pass penalties on to the customer when they override the request to curtail. This highlights the uncertainty and additional cost associated with relying on demand response programs to meet peaking capacity needs.

Additionally, as part of the ENO 2015 IRP, the Company engaged ICF to conduct an analysis of the long-term DSM potential achievable in New Orleans. ICF concluded that cost-effective DSM could potentially avoid a cumulative 112 MW of peak demand by the end of the 20-year study period.[17] Importantly, it takes time to design programs, develop marketing materials, and ramp up spending, thus limiting the amount of DSM potential that can be achieved in the near-term. For example, ICF estimates that by 2019, approximately 49 MW of cumulative peak demand could be avoided through cost-effective DSM programs. As shown in Table 2 above, the Company needs approximately 377 MW of peaking and reserve capacity by 2020, which far exceeds the capacity of the cost-effective DSM potential identified by ICF in the near-term. Moreover, the Company's long-term peaking and reserve capacity needs exceed the capacity associated with NOPS, thus leaving ample room to pursue cost-effective DSM potential over the planning horizon.

Q41. WOULD IT BE PRUDENT TO RELY ON THE MISO ANNUAL PLANNING RESOURCE AUCTION TO MEET LONG-TERM RESOURCE NEEDS?

A. No. While the MISO PRA provides a short-term option to meet customers' needs, over-reliance on the short-term market in lieu of long-term resources – especially at a time when market conditions are expected to begin tightening toward equilibrium – involves greater risk compared to a long-term resource such as NOPS, as explained below. I note that, by reliance, I mean a circumstance in which the Company does not have enough long-term owned or controlled capacity sufficient to meet its long-

[17] In its conclusions, ICF noted that DSM potential studies are forecasts, and thus contain a margin of error and uncertainty with respect to the ability to achieve estimated potential.

term needs, and it seeks to satisfy that deficit with short-term capacity purchased from others in the MISO auction (which purchases are valid only for one year).

Q42. WHEN ARE MARKET CONDITIONS EXPECTED TO TIGHTEN?

A. While the exact timing is unknown, based on an assessment of capacity supply, including third party resources that could be available to the Company through PPAs, and peak demand in the MISO South region, the Company currently projects that the MISO capacity market will reach supply/demand equilibrium in the year 2022. In addition, the 2015 OMS MISO Survey produced by MISO in July 2015 indicates that MISO believes market equilibrium could be reached in the 2020 timeframe across the entire MISO footprint.

Q43. PLEASE EXPLAIN THE CIRCUMSTANCES THAT INFLUENCE MARKET EQUILIBRIUM.

A. Market conditions in MISO South and the entire MISO market are driven by the demand for, and supply of, capacity, which is expected to change over time. As load grows and/or generating resources deactivate, which is the situation today, there will be a time when demand equals or exceeds the available generating capacity, absent the construction of new generation resources. Importantly, the balance of supply and demand in the MISO annual PRA should not be extrapolated to infer the balance of demand for and supply of long-term generating capacity, as the auction is limited to one planning year ahead. The future availability of long-term capacity is determined by a variety of factors that are independent of MISO's annual RA process.

Q44. WHAT ARE THE CONSEQUENCES OF REACHING MARKET EQUILIBRIUM?

A. Equilibrium is the point at which supply, including third-party resources, and demand, including appropriate planning reserves, are in balance. Put differently, equilibrium is the point at which the price signal for capacity approaches the cost of new build. Thus, as equilibrium approaches, the price for capacity is expected to increase significantly from current levels. Furthermore, as recent industry trends have shown, current and projected prices for natural gas coupled with increasing pressures to move away from carbon-intense fuel sources are leading to an increase in the demand for lower carbon alternatives such as modern natural gas-fired CT technologies. As demand for these types of resources increase, the cost for labor and materials necessary to construct and install new CT resources would be expected to increase. Deferring deployment of new CT resources nearer to, or even after, market equilibrium will expose customers to increased risk of significantly higher costs due to the labor and equipment premiums and long lead times that would be required for those resources. Moving forward with deployment of NOPS now will mitigate customers' exposure to higher capacity prices as equilibrium approaches as well as the potential cost premium and longer lead times that may be required for new CT resources as equilibrium occurs.

Q45. CAN YOU PROVIDE AN EXAMPLE OF THE RISK ASSOCIATED WITH THE PRICE FOR CAPACITY INCREASING AS THE MARKET APPROACHES EQUILIBRIUM?

A. Yes. Earlier this year, MISO published the results of the PRA for the 2016/2017 Planning Year, which began June 1, 2016. MISO reported that the Auction Clearing Price ("ACP") for Local Resource Zones ("LRZ") 2 through 7 (*i.e.*, majority of MISO North) was $72/MW-day. In sharp contrast, the ACP for LRZ 2 through 3 and 5 through 7 for the prior 2015/2016 Planning Year was $3.48/MW-day, representing over a 20-fold increase in the ACP from the 2015/2016 to 2016/2017 Planning Year. MISO explained that the increase was driven in part by a 4,500 MW decline in capacity bid into the PRA in MISO North. This highlights the uncertainty associated with relying on the MISO annual PRA to meet long-term resource needs, which exposes customers to greater risk.

Q46. COULD THE RESOURCE NEEDS OF ENO BE MET SOLELY THROUGH TRANSMISSION UPGRADES?

A. No. As explained above, the MISO capacity market is tightening and is expected to reach equilibrium early in the next decade, if not sooner. Upon reaching equilibrium, no amount of transmission investment will be able to address the resource needs of the Company as there will be no excess capacity to serve load.

In addition to mitigating market risks, as discussed by Company witness Charles Long, there are important reliability and economic factors associated with locating generating resources close to load in order to reduce reliance on transmission where possible and improve reactive power capability and the ability to dynamically regulate voltage. Moreover, as discussed by Mr. Long, there are voltage and local reliability ("VLR") needs in the region that includes ENO's load zone, as determined by MISO, that are most economically and effectively addressed through incremental local area generating capacity. As Mr. Long explains, NOPS will likely have a VLR role in DSG, and if the unit is not constructed, significant large-scale transmission projects would be necessary to maintain reliability over the long-term, ten-year planning horizon. As discussed above, meeting a portion of the Company's long-term needs with local area generating resources will support longer-term reliable operations by ensuring adequate local generating resources are available to facilitate planned generator and transmission outages, mitigate risks associated with unplanned outages, and reduce reliance on transmission imports to serve ENO's load. In addition, local generation will enhance ENO's ability to restore service in the aftermath of a severe weather event, including a hurricane. As indicated in Table 4, the Company already relies heavily on resources external to both its service area and the load pocket, which supports the addition of NOPS to mitigate these and other market and supply related risks.

IV. TECHNOLOGY AND SITE SELECTION

A. Selection of the CT Technology

Q47. HOW DID THE COMPANY DETERMINE THE APPROPRIATE CT TECHNOLOGY FOR NOPS?

A. A technology assessment was conducted in 2015 that considered seven different CT technologies: four large frame CTs, two aero derivative CTs, and one internal combustion engine ("ICE"). The analysis included an assessment of qualitative and quantitative factors consistent with ENO's peaking capacity needs. The results of the analysis support the selection of NOPS as the preferred CT technology, and the analysis is included as Exhibit SEC-5 to my testimony.

Q48. WHAT SPECIFIC CONCLUSIONS WERE DRAWN FROM THE 2015 ASSESSMENT THAT SUPPORTS THE SELECTION OF NOPS AS THE PREFERRED CT TECHNOLOGY?

A. The 2015 assessment evaluated the alternative technologies against a range of factors, including fixed and total supply cost, operational flexibility, ENO's planning needs, and gas pressure requirements. The results showed that selection of the Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC large frame CT best fit ENO's planning needs because it provides the highest capacity rating and lowest total supply cost of all seven technologies. In addition, it has a comparable heat rate and competitive ramping rates to provide operational flexibility.

Q49. WERE THERE ANY ADDITIONAL CONCLUSIONS IMPORTANT TO THE SELECTION OF NOPS?

A. Yes. The economic assessment examined the supply costs of each of the seven alternatives based on an assumed 30-year operating life. As shown in Exhibit SEC-5, even though the MHPSA 501 GAC provides the most capacity of all the alternative machines analyzed, it ranked the lowest in terms of total supply costs. It was followed by the three other large frame CTs, then the two aero derivatives, and finally the ICE. Thus, although smaller-sized units were considered, the larger MHPSA 501 GAC proved to be the most economic solution.

Q50. IS THE SELECTION OF THE MHPSA 501 GAC CONSISTENT WITH THE TECHNOLOGY ASSESSMENT IN THE 2015 IRP?

A. Yes. The Generation Technology Assessment in the 2015 IRP evaluated a range of supply-side resource technologies, including a range of CT technologies and sizes. The CT technologies evaluated included a large aero-derivative CT as well as a small and large Frame CT. The assumptions for each technology were meant to be representative of the cost and performance for each *class* of CT and not specific to a particular manufacturer since there are multiple manufacturers that offer some or all of the technologies evaluated.

Consistent with the Company's identified long-term peaking and reserve capacity needs, the Company completed the analysis summarized in Exhibit SEC-5 to inform the selection of a CT technology that considers the cost and performance of the particular manufacturers' product offerings. That analysis confirms the conclusion reached in the Draft and Final 2015 IRP that a large frame CT is the preferred CT technology to meet the Company's long-term peaking and reserve capacity needs. Moreover, the analysis in Exhibit SEC-5 provides the rationale for the particular CT chosen for NOPS – the MHPSA 501 GAC – over the other alternatives, including other large Frame CTs.

Q51. HAVE YOU CONDUCTED A MORE RECENT TECHNOLOGY ASSESSMENT?

A. Yes. In March 2016, the Company conducted an assessment using the best available information for the MHPSA 501 GAC as well as two alternative CTs. That assessment included a screening level analysis comparing the MHPSA 501 GAC and GE 7FA.05 large frame CTs and the smaller GE LMS100 aero derivative CT. That screening level analysis is summarized in Figure 2 below, and confirms the selection of the MHPSA 501 GAC over the GE 7FA.05 and GE LMS100 CTs.

Figure 2 Highly Sensitive Protected Materials

[redacted]

Q52. WAS A MORE DETAILED ECONOMIC EVALUATION CONDUCTED AS PART OF THE 2016 ASSESSMENT?

Yes. As a part of the 2016 assessment, the Company evaluated the total supply cost of the MHPSA 501 GAC and the smaller GE LMS100 using the AURORA production cost model to determine if the economics of deploying a single GE LMS100 in 2019 and deferring the addition of a second GE LMS100 until a later date could result in a lower total supply cost as compared to deploying the larger MHPSA 501 GAC in 2019.

Q53. DID THAT ECONOMIC ANALYSIS CONFIRM THE SELECTION OF MHPSA 501 GAC FOR NOPS?

A. Yes. Figure 3 summarizes the results of the total supply cost component of the 2016 economic analysis comparing the MHPSA 501 GAC in 2019 (*i.e.*, Alternative 1) to deploying the first GE LMS100 in 2019 and then a second GE LMS100 in each year of the analysis (*i.e.*, Alternative 2). As shown in Figure 3, Alternative 2 is inferior because the total supply costs exceed that of Alternative 1 in each year regardless of how long the addition of the second GE LMS100 is deferred.

Figure 3 Highly Sensitive Protected Materials

[redacted]

Q54. WERE OTHER FACTORS CONSIDERED IN THE 2016 ASSESSMENT THAT SUPPORTS ALTERNATIVE 1?

A. Yes. As shown in Exhibit SEC-6, in addition to the evaluation of total supply cost, the Company also considered qualitative factors in determining the preferred alternative, including locational considerations, transmission upgrades, market risks, local area reliability, technology risks, and financing/capital requirements. The scoring on the qualitative assessment supports the selection of the MHPSA 501 GAC over the GE LMS100.

Q55. PLEASE SUMMARIZE THE RESULTS OF THE 2016 ASSESSMENT.

A. Deploying the MHPSA 501 GAC in 2019 results in the lowest total supply costs and best meets ENO's long-term resource needs and stated planning objectives of cost, reliability, and risk mitigation:

- the MHPSA 501 GAC more closely aligns with ENO's need for long-term peaking and reserve resources and will provide additional local area generation in support of longer-term reliable operations within the Company's service area, while mitigating market and supply related risks;
- the MHPSA 501 GAC provides better overall economics through a lower fixed cost commitment on a total dollar investment, and $/kW installed cost, as compared to deploying one GE LMS100 in 2019 and deferring the addition of a second GE LMS100 until a later date;

- the MHPSA 501 GAC will mitigate risks associated with the increasing cost of capacity, including construction and material costs, through a known and measurable upfront investment to meet long-term needs;
- the relative economics of the MHPSA 501 GAC are not dependent on the market for capacity prices in MISO; and
- deploying the MHPSA 501 GAC will allow the Company to leverage a growing fleet with operational experience and efficiencies associated with operating and maintenance costs.

B. Site Selection

Q56. HOW WAS THE SITE SELECTED FOR THIS PROJECT?

A. Based on the local considerations discussed above, and in accordance with the Council's directive in Resolution R-15-524, which directed the Company to use "reasonable diligent efforts" to pursue development of a peaking resource in the City following termination of the ESA, the site selection process involved identification of potential locations for the development of new generation in Orleans Parish. Considerations included factors related to fuel supply, transmission, existing infrastructure, site suitability, and environmental regulations.

Q57. WHAT ALTERNATIVE SITES WERE CONSIDERED FOR THE LOCATION OF NOPS?

A. As shown in Exhibit SEC-5, two potential sites in Orleans Parish were evaluated for new unit suitability: A.B. Paterson and Michoud. A.B. Paterson was eliminated due to limited fuel and other infrastructure. Michoud is located closer to three major gas pipelines, and it has existing office building infrastructure as well as available bays in the high-voltage switchyard for interconnection to the transmission system. In addition, the Michoud substation is more strongly interconnected to the Company's service area and the load pocket more broadly, via multiple lines at both 230 kV and 115 kV voltages, which enables a resource at the Michoud site to provide more support to local reliability versus a resource interconnected at the A.B. Patterson site.

C. Project Approval

Q58. DID THE ENO OPERATING COMMITTEE APPROVE THE CONSTRUCTION OF NOPS?

A. Yes. Based on the analysis presented in Exhibit SEC-6, the ENO Operating Committee approved NOPS on March 31, 2016.

V. CONCLUSION

Q59. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's long-term resource planning process indicates a need for capacity, including additional peaking and reserve capacity. Local considerations indicate that it would be most beneficial to customers to locate this new capacity in Orleans Parish, particularly considering the deactivation of Michoud Units 2 and 3. Locating the unit in Orleans Parish also provides reliability benefits by being close to the load it serves. Finally, the construction of additional long-term generation in the Company's service area, such as NOPS, will mitigate risk to the Company's customers associated with

MISO capacity and energy market price volatility, enhance the Company's ability to restore service following severe weather events, and comply with the Council's directive in the System Agreement settlement to pursue locating a peaking resource in Orleans Parish.

Q60. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SETH CUREINGTON**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Seth Cureington

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 17th DAY OF JUNE, 2016

NOTARY PUBLIC

My commission expires: at death

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life

SETH E. CUREINGTON

PRIOR TESTIMONY BEFORE COUNCIL FOR THE CITY OF NEW ORLEANS

Docket	Date	On Behalf Of	Subject
UD-14-02	October 2014	Entergy New Orleans, Inc.	Algiers Transfer
UD-15-01	February 2015	Entergy New Orleans, Inc.	Union PPA
UD-15-01	August 2015	Entergy New Orleans, Inc.	Union Power Block 1

MISO

MISO Overview

NARUC Winter Meeting

February 2015

MISO focus is broad in response to the nation's changing energy landscape

- **Environmental Regulations –** managing transition to Mercury and Air Toxics Standards (MATS) and preparing for Clean Power Plan (111(d))
- **Resource Adequacy** – efforts being taken to ensure adequacy throughout entire year and accommodate a changing portfolio
- **MISO Processes and Procedures –** review / revise to align as industry continues to evolve
- **Seams Management and Optimization** – enhancing reliable movement of resources to minimize cost to end user

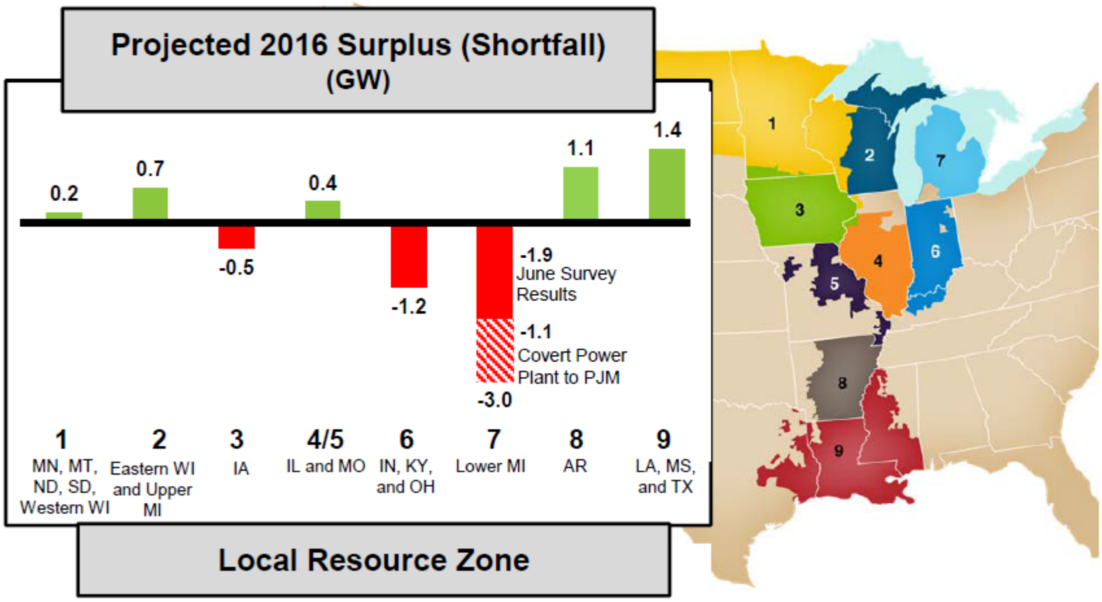
MISO

The generation fleet in MISO is affected by multiple environmental regulations

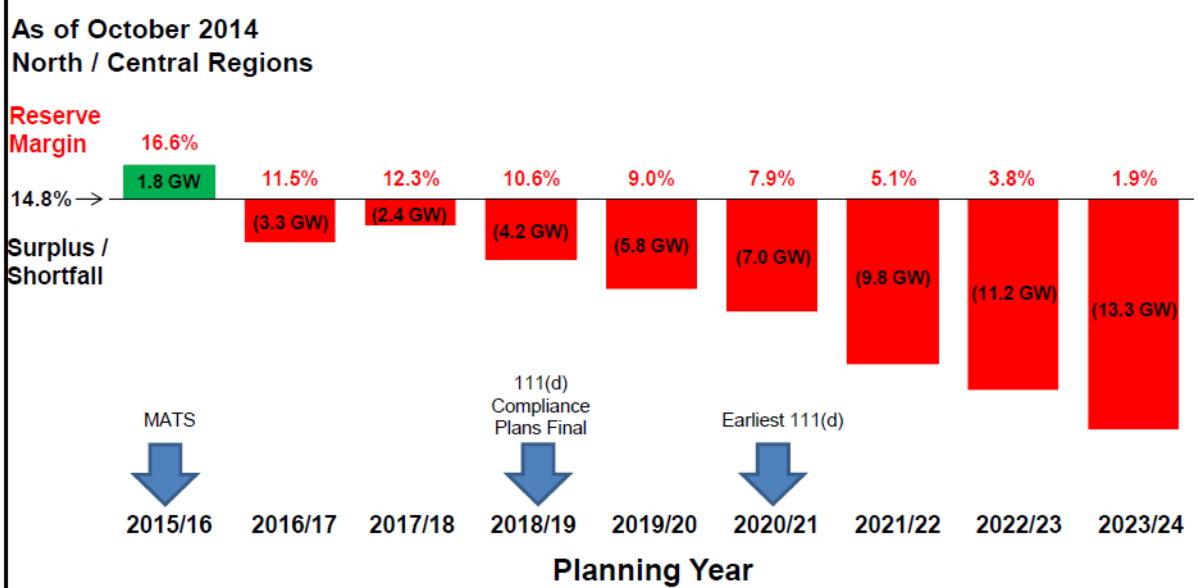
	MATS	CSAPR & CWIS	Draft Clean Power Plan 111 (b) & (d)	NAAQS & Coal Ash
Nature of Regulation	Mercury and Air Toxics Standards	Cross State Air Pollution Rule and Cooling Water Regulations (316(b))	CO_2 from existing and new power plants	New air quality standards/ Coal ash storage
Compliance Dates	2015 / 2016	As early as 2015	2015/16 (New) Beginning in 2020 (Existing)	???
Impacts	• Significant coal retirements • Outage coordination challenges • Shrinking reserve margins around MISO • Growing dependence on natural gas	• NO_x requirements tightened • Higher plant compliance costs influence retirement decisions	• New coal requires CCS; baseload capacity options reduced • Significant coal retirements • Increased dependence on gas and carbon neutral resources	• Increased costs • Other potential impacts depend on regulations

Current projections illustrate resource adequacy risk

As of October 2014



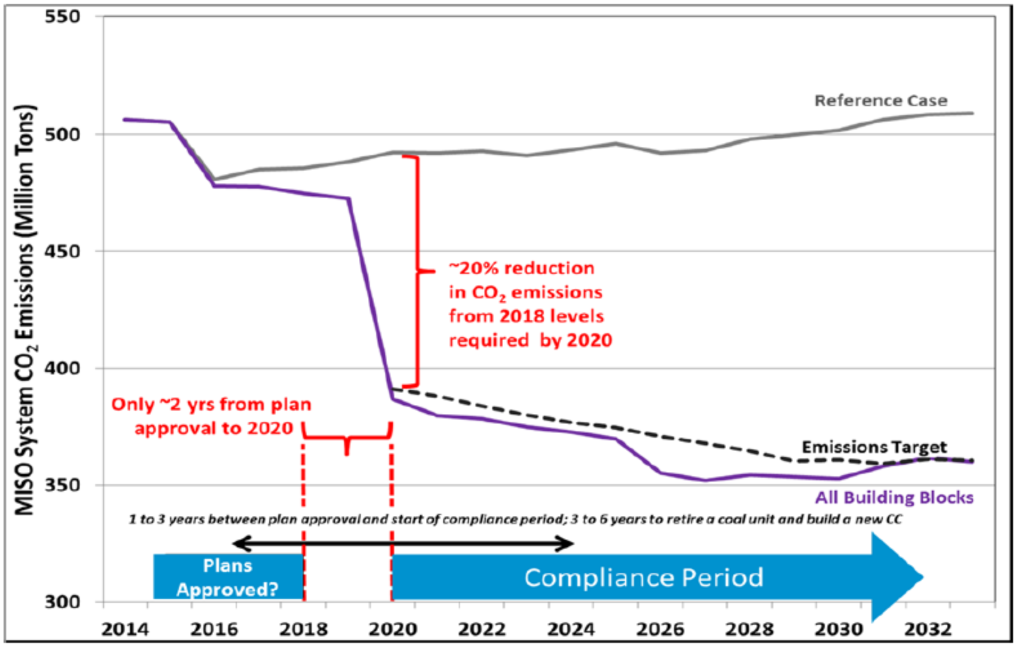
The region is showing a need for additional resources to meet projected load growth (0.8%)



10-year **preliminary forecast**, NERC Long Term Reliability Assessment.

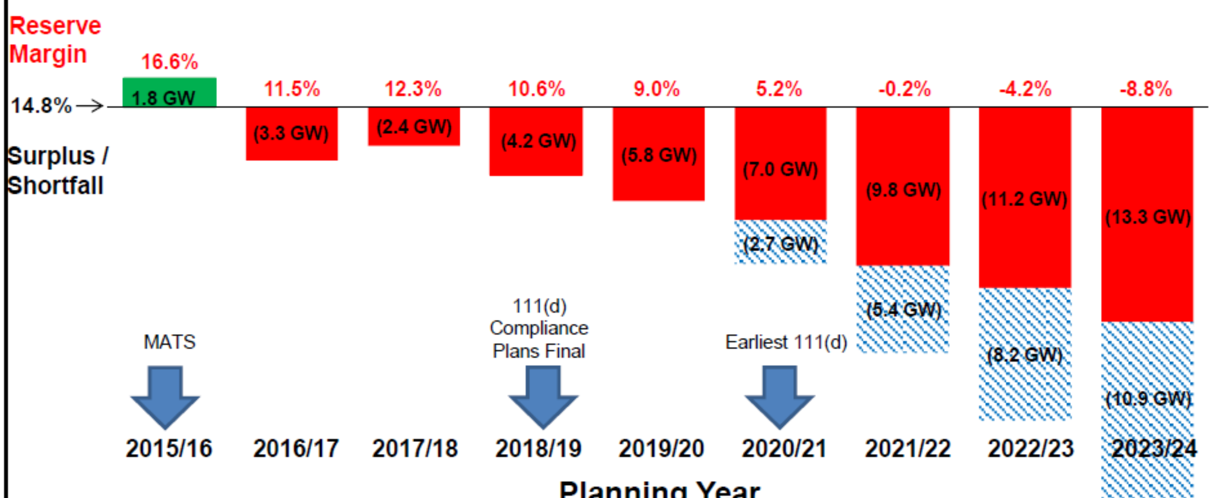
Values reflect Covert Power Plant to PJM

The Clean Power Plan (CPP) will further impact the fleet with a timeline that may limit compliance strategies



Additional retirements driven by the CPP will exacerbate the supply situation

As of October 2014
North / Central Regions

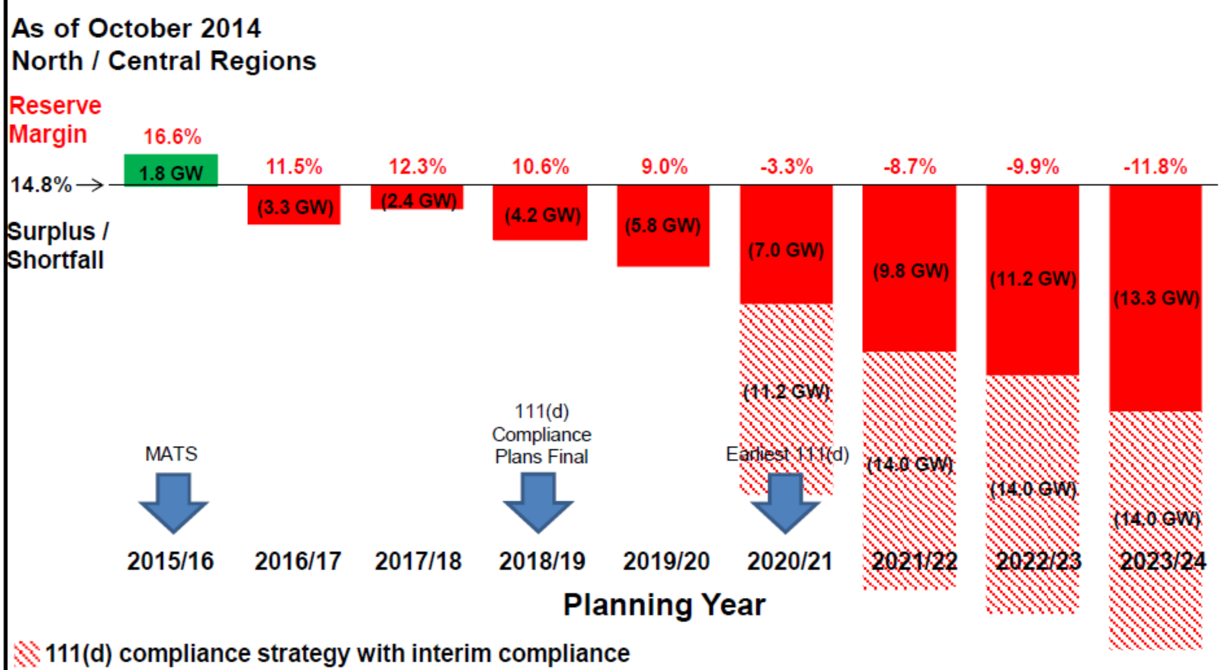


111(d) compliance strategy without interim compliance

10-year **preliminary forecast**, NERC Long Term Reliability Assessment.

Values reflect Covert Power Plant to PJM

Interim average performance requirements beginning in 2020 would accelerate the timeline and magnitude of need



10-year **preliminary forecast**, NERC Long Term Reliability Assessment.

Values reflect Covert Power Plant to PJM

MISO is engaged to ensure reliability risks from the plan are understood and mitigated

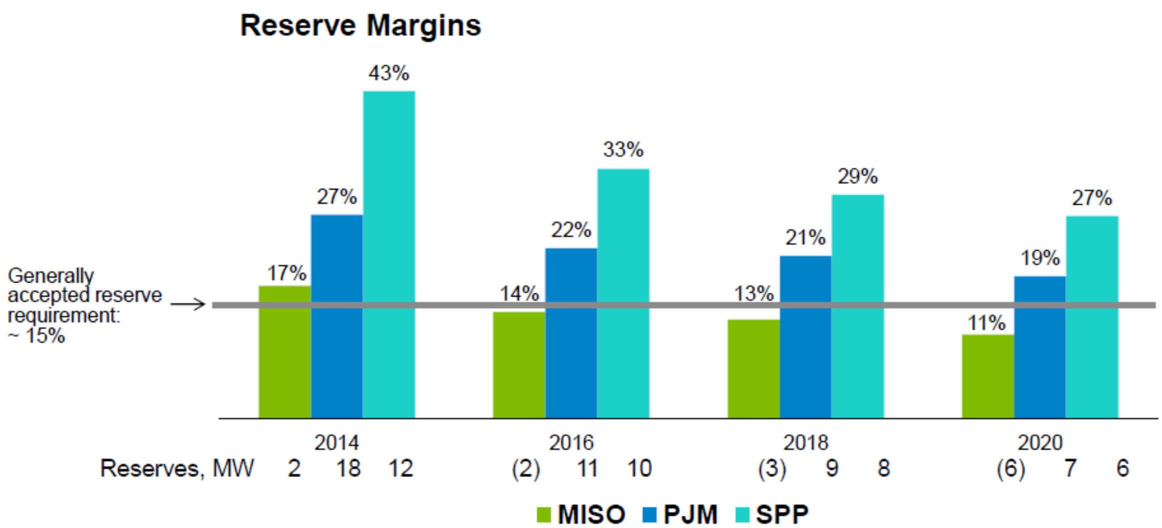
- Filed comments requesting EPA flexibility in November
  - Focused on reliability; cumulative impact of retirements has the potential to stress transmission system reliability
  - Insufficient time available to plan and implement new generation, transmission and natural gas infrastructure
- Participating in FERC Technical Conferences
  - FERC will address reliability, markets and energy infrastructure
  - National conference at FERC's offices on February 19; regional meeting scheduled for March 31 in St. Louis
- Preparing for increased utilization of gas generation
  - Currently participating in cross-industry discussion on misalignment of gas and electric market timelines
  - Improved communication and coordination with pipeline operators
  - Pipeline status information made available to MISO Operators
  - Lack of product harmonization remains a challenge

We are reviewing our processes and procedures to ensure they promote reliability

- Transparency via annual OMS-MISO survey
- Evaluate seasonal resource accreditation
  - Demand response
  - Reliable fuel supply
  - Deliverability
- Explore transition to EPA MATS compliance
  - Six-week timing gap
  - Product and exchange facilitation
- Evaluate implications of adjacent market rule changes
  - PJM capacity performance initiative
  - Inter-market deliverability
- Assessing alignment of processes and procedures
  - Resource Adequacy
  - Outage coordination
  - Interconnection and disconnection (retirement) process
  - Transmission service requests
  - Zonal modeling

MISO

The reliable transfer of resources inter-regionally holds benefit for end-users



Source: 2014- NERC 2014 Summer Assessment; SPP 2016-2020 – NERC 2013 long-term assessment; PJM 2016-2020 – PJM BRA results and MISO analysis; MISO 2016-2020 - 2014 OMS-MISO Survey Update June SAWG

Collaboration with our neighbors is ongoing; regional stakeholder differences complicate seams progress

- PJM
  - Discussion of options to ensure interface prices appropriately reflect congestion costs continue
  - Coordinated planning study underway to evaluate historical congestion and identify solutions for regional approval in 2015
  - Interregional Order 1000 filing conditionally accepted by FERC
- SPP
  - Market-to-Market with SPP approved by FERC to begin on March 1
  - Progress toward a resolution being made on the JOA dispute
  - Jointly screening stakeholder submitted transmission solutions to historical congestion issues as part of our coordinated planning effort
- Joint Parties (Southern Company, TVA, Associated Electric, PowerSouth, LGE/KU)
  - Working with parties on short-term extension of Operations Reliability Coordination Agreement (ORCA) and on long-term protocols for coordination and operation post-ORCA

MISO focus is broad in response to the nation's changing energy landscape

- **Environmental Regulations –** managing transition to Mercury and Air Toxics Standards (MATS) and preparing for Clean Power Plan (111(d))
- **Resource Adequacy** – efforts being taken to ensure adequacy throughout entire year and accommodate a changing portfolio
- **MISO Processes and Procedures –** review / revise to align as industry continues to evolve
- **Seams Management and Optimization** – enhancing reliable movement of resources to minimize cost to end user

RECEIVED
October 31, 2014
INDIANA UTILITY
REGULATORY COMMISSION

Indianapolis Power & Light Company

2014 Integrated Resource Plan

Public Version

October 31, 2014

ipl®
an AES company

construct with a seasonal construct or to add seasonal capacity products. A Seasonal Construct is favored by utilities with an obligation to serve as aligns better with its obligations to customers, allows utilities to better adapt changing market, business, and regulatory landscapes, and addresses the winter peaking issues of natural gas. IPL is a leader in the resource adequacy related stakeholder process and actively provides substantive comments to MISO to influence change in the best interests of our customers.

Planning Reserve Margin Modeling

IPL's minimum PRMR established by MISO for 2014 equates to an effective 14.8% reserve margin, representing an increase from 2012 (13.1%) and 2013 (14.2%). As identified above, many factors are used by MISO to establish an LSE's resource adequacy requirement. The LSE's planning reserve margin changes annually as MISO modifies its LOLE analysis and as a result of changes in its EFORd and diversity. IPL's ICAP ratings can also change annually due to the results of unit testing. For Ventyx's long term modeling purposes in this IRP, IPL identified a 14% planning reserve margin to be used consistent with IPL's summer-rated capacity. This long-term modeling number provides for targeted reserves in the range of future expected MISO-determined resource needs and is consistent with the MISO specific calculations shown in Figure 4.3.

Planning Year beginning June 1, 2015 and ending May 31, 2016

IPL is retiring its Eagle Valley units 3 through 6 by April 16, 2016 to comply with its MATS deadline. However, this retirement date is 6.5 weeks before the end of the 2015-2016 MISO Planning Year. MISO's current resource adequacy requirement states a capacity resource that clears a planning reserve auction must be available during the entire commitment period otherwise replacement capacity from the same zone must be secured to avoid tariff compliance penalties levied by FERC. During this 6.5 week low load period IPL has capacity in excess of its requirement to reliably serve its load. The requirement to buy additional capacity is unjust and unreasonable and would be merely a transfer of wealth with no impact on resource adequacy for IPL or Zone 6. In order to avoid the excess costs associated with this provision, on June 20, 2014, IPL submitted a request to FERC to waive the replacement requirement needed during the stated 6.5 week timeframe. With the support of the IURC comments filed with FERC, this request was granted by FERC on October 15, 2014. As a result of FERC granting the Waiver Request, IPL and its customers will not be forced to bear the costs of unneeded capacity.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT SEC-4

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT SEC-5

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT SEC-6

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT SEC-7
(on CD)

JUNE 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-________**

DIRECT TESTIMONY

OF

JONATHAN E. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND PURPOSE

A. Qualifications

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Jonathan E. Long. My business address is Parkwood Two Building, 10055 Grogan's Mill Road, The Woodlands, Texas 77380.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, Inc. ("ESI")[1] as Vice President, Project Management. In that capacity, I was responsible for preparing the New Orleans Power Station project ("NOPS" or the "Project"), which included coordinating project team's activities and securing all permits and contracts necessary to construct the project.

Q3. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Electrical Engineering from Mississippi State University in 1982 and a Master of Business Administration degree from Pepperdine University in 1991.

I have worked in the energy industry since 1982. All but two years of that experience has been focused on the development, construction, and operation of power generation facilities. Earlier in my career (1987-1989), I was the plant engineer for the construction, start-up, and initial operation of two coal-fired,

[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans, Inc. ("ENO"), and Entergy Texas, Inc. ("ETI").

circulating fluidized bed power generation facilities in central California. From 1995 to 2006, I was employed by Entergy Enterprises, Inc. and participated in the development, construction, and operation of power generation facilities for the unregulated subsidiaries of Entergy Corporation. I was a key contributor to the development, construction, and operation of the 1,200 megawatt ("MW") Saltend Cogeneration Facility in East Riding of Yorkshire, England and the 800 MW Damhead Creek Generating Facility in County Kent, England.

In 2006, I accepted a position at ESI and began participating in the development and planning of power generation facilities for the regulated subsidiaries of Entergy Corporation, including projects such as the repowering of Little Gypsy Unit 3, the development of a self-build option to be market tested in the Western Region Request For Proposals, the development of the Ninemile 6 self-build option that was market tested in the Summer 2009 Request for Proposals for Long-Term Supply-Side Resources, and the implementation of that project after it was selected. I was responsible for negotiating the EPC agreement for Ninemile 6, recruiting and hiring the project management staff and retained a leadership position in that project through its completion.

My history in developing and constructing fossil generation provides me with significant experience with the development of cost estimates for power plant projects, the negotiation and administration of large contracts for the construction of power plants, and the procurement of services of major equipment vendors.

Q4. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am testifying before the Council of the City of New Orleans ("CNO" or the "Council") on behalf of ENO in support of the proposed Project.

B. <u>Purpose of Testimony</u>

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony supports the Company's Application in this proceeding, which seeks, among other things, approval to proceed with constructing an advanced combustion turbine ("CT") with a nominal size[2] of 226 MW at the Michoud facility in New Orleans, Louisiana. I first provide an overview of the proposed Project. I next explain how the self-build commercial team developed the cost estimate associated with the Project. I then present the current cost estimate and schedule associated with NOPS. I then describe the management approach that the Company intends to employ and the process used to select Chicago Bridge & Iron, Inc. ("CB&I") to provide engineering, procurement, and construction ("EPC") services. I also discuss the risk mitigation measures put in place to control Project risks. Finally, I discuss the status of the required permits/approvals for NOPS.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COUNCIL?

A. Yes. I have previously submitted testimony in LPSC Docket Nos. U-30192 (Phase I), U-31971, and U-33770.

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[2] Nominal size refers to the general size of the unit. As discussed later in my testimony, actual output of a unit depends on a number of factors that vary from unit to unit and site to site.

II. PROJECT OVERVIEW

Q7. PLEASE PROVIDE A BRIEF OVERVIEW OF THE NOPS PROJECT.

A. NOPS will provide approximately 226 MW (nominal) of summer generating capacity, consisting of one Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC CT. The plant will be located in New Orleans, Louisiana adjacent to the existing Michoud facility. The base elevation of the unit will be 3.5' above sea level. Allowance for a flooding event similar to Hurricane Katrina was included in the design of the power block elevation. The unit will be protected by levees constructed along the Intracoastal Waterway, and the Lake Borgne surge barrier that were constructed/improved after Hurricane Katrina.

The Project will be constructed by CB&I under a fixed price,[3] fixed schedule form of EPC contract, and, including an allowance for funds used during construction ("AFUDC"), will cost an estimated $216 million, or roughly $955 per kW, including the costs to interconnect to the switchyard. If there are no unanticipated project delays due to the inability to obtain necessary regulatory approvals, permits, materials and equipment, NOPS is expected to enter service in the second half of 2019.

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[3] Throughout my testimony, I refer to the EPC agreement with CB&I as a "fixed-price" form of EPC agreement. It should be noted that while the EPC agreement with CB&I is a fixed-price form of contract, there are elements of the pricing that are not fixed, which will be discussed below in my Direct Testimony. The primary elements that are not fixed are the craft labor and *per diem* escalation provisions in the NOPS EPC Agreement. These provisions in the EPC Agreement are designed to clearly allocate the risk of escalating labor and *per diem* rates in the Gulf Coast region during the period of construction. These provisions are explained more fully later in my Direct Testimony.

Q8. WHAT IS THE EXPECTED OUTPUT OF NOPS?

A. As stated, NOPS is designed to reach a nominal output of 226 MW. The actual maximum output of the unit will depend on the following variable factors and conditions: ambient air temperature, relative humidity, Btu content of natural gas delivered at the unit, and number of operating hours since the last maintenance interval. By way of illustration, NOPS, in a new and clean condition, would be expected to generate approximately 226 MW based on summer conditions of 97° F and 59% relative humidity.

HSPM Table 1: Base Proposal Predicted Unit Performance

[redacted]

Q9. DOES THE ENTERGY SYSTEM HAVE ANY RECENT EXPERIENCE WITH BUILDING GENERATING UNITS?

A. Yes. Another EOC, ELL, has recently completed a self-build combined-cycle gas turbine unit ("CCGT"), Ninemile 6, which was completed roughly 10% under-budget and months ahead of its projected in-service date, successfully producing savings for customers.[4]

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[4] It should be noted that ENO purchases 20% of the capacity and energy of Ninemile 6 through a purchase power agreement ("PPA") with ELL.

III. DEVELOPMENT OF COST ESTIMATES

Q10. WHAT ROLE DID YOU PLAY IN THE DEVELOPMENT OF THE NOPS PROJECT?

A. I have led the Project since the decision to develop NOPS. I have been the primary person responsible for the development of the Project, including negotiating the terms of the contracts under which NOPS will ultimately be constructed.

Q11. WHAT RESOURCES WERE UTILIZED TO DEVELOP THE OVERALL COST ESTIMATE?

A. The following are the Project's two major cost components along with the resources used to develop the estimates:

1) EPC agreement costs ("EPC Costs"): CB&I, at the request of ESI, provided a cost estimate utilizing preliminary engineering. CB&I's EPC estimate formed the basis of the EPC Costs contained in the NOPS proposal.
2) Costs outside of the EPC agreement ("Non-EPC Costs"): The Project team developed these costs using internal subject matter experts and third-party providers (*i.e.*, Sargent & Lundy as owner's engineering and other technical consulting firms). Later in the testimony, I will expand upon the components of these Non-EPC Costs.

Q12. DID THE COST ESTIMATE FOR NOPS INCLUDE A REASONABLE LEVEL OF DESIGN INFORMATION?

A. Yes. ESI, working with CB&I, developed a site-specific preliminary design and cost estimate. As stated, the largest single component of the total Project cost estimate is the EPC Costs. CB&I developed their job-specific general arrangement drawings, arrangements sketches, and electrical one-line diagrams. Quantities were developed to reflect the NOPS site and process conditions utilizing input from their current in-house estimates for similar projects updated to reflect specific layouts, processes, and design definition for the site. The MHPSA 501 GAC gas turbine was incorporated into CB&I's design.

A. Site Configuration and Technology Selection

Q13. WHAT IS THE CURRENT STATUS OF THE SITE ON WHICH NOPS IS PROPOSED TO BE LOCATED?

A. The Project is proposed to be located at the Michoud facility in New Orleans, Louisiana. The existing Michoud units have been deactivated. Thus, no operations will be impacted. Ample space is available for construction and laydown of NOPS at the Michoud site. The existing administration building, warehouse, machine shop and deep well infrastructure are expected to be used for the project. For reference, I have attached Exhibits JEL-1 through JEL-3, which illustrate NOPS' location.

Q14. PLEASE EXPLAIN WHY THE COMPANY PROPOSED THE MHPSA 501 GAC COMBUSTION TURBINES AS THE PREFERRED TECHNOLOGY FOR NOPS.

A. As discussed by Mr. Cureington, ENO is in need of a CT technology to meet its capacity, supply role, and reliability needs. The project team accordingly evaluated several different technologies in order to meet that need. As discussed more fully by Company witness Seth Cureington, the MHPSA 501 GAC was a better economic option for ENO's customers, considering the total relevant supply cost method, which included comparing fixed costs, variable production cost, Midcontinent Independent System Operator, Inc. ("MISO") capacity purchase costs and transmission. It should also be noted that other Entergy companies have had a positive prior experience with Mitsubishi Heavy Industries[5] as a supplier of gas and steam turbines.[6]

Q15. IS THE PROJECT CONSTRUCTION PRICING FIXED AT $216 MILLION?

A. No. As mentioned earlier, project costs consist of EPC Costs and Non-EPC Costs. The Non-EPC Costs are not fixed. Moreover, while the EPC contract price is fixed assuming the defined scope of work and a timely issuance of full notice to proceed ("NTP"), other factors such as changes in scope due to discovery of new facts, force majeure events, delay in issuing notice to proceed, craft labor wage rate and *per diem* rate escalation, or changes in law could affect EPC Costs. Those subsequent evaluations could result in change orders that increase or decrease EPC Costs. Also, development projects spanning several years are exposed to a number of risks, both

[5] MHPSA is a combination of units of MHI and Hitachi Corporation.

[6] Entergy's non-regulated power group has built, owned, and operated two power plants in the United Kingdom that utilized a total of five MHI 701F gas turbines and four MHI steam turbines.

known and unknown, and despite diligent mitigation plans and efforts, scope changes may be required.

Q16. CAN YOU PROVIDE AN EXAMPLE OF A DEVELOPMENT THAT COULD REQUIRE A CHANGE IN SCOPE OF WORK AND CHANGE THE PROJECT'S COST ESTIMATE?

A. One example of a development that could change the Project's scope of work is a discovery event. For example, it would not be unusual that over the long history of the Michoud power plant, a cable for temporary power supply was buried. If that cable is uncovered during excavation, work must stop until it is investigated and ensured to be safe. Any work that the Contractor has to perform related to that discovered cable would be added to the scope of the Project through a change order.

IV. ESTIMATED PROJECT COST AND SCHEDULE

Q17. WHAT IS THE CURRENT ESTIMATE OF THE COSTS TO COMPLETE NOPS?

A. The current estimate of NOPS' costs, based on the EPC agreement, is approximately $216 million, or roughly $955 per kW, inclusive of, among other things, expenses related to seeking Council certification, costs related to transmission interconnection to the switchyard, contingency, and AFUDC. A summary of the components of the current cost estimate is shown below:

HSPM NOPS Capital Cost Estimate (Millions)

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Q18. HOW WERE THESE COST ESTIMATES PREPARED?

A. These estimates are largely derived from the largest single cost component, the EPC agreement with CB&I. CB&I was selected to serve as the EPC contractor for the project through a competitive solicitation process that was finalized in September 2015. The Project team conducted a competitive procurement process, soliciting four contractors to participate, which validated that EPC pricing offered by CB&I was competitive within the current market for such services, as CB&I's price was the lowest of the four bidders. CB&I was also chosen based on its strength of performance on the Ninemile 6 project, commercially reasonable pricing, and knowledge of Entergy's processes gleaned from prior projects. The EPC agreement includes a detailed scope of work describing the plant, its required functionality, and its required performance, which was developed by CB&I based on the preliminary engineering described earlier in my testimony.

As briefly mentioned above, Non-EPC Costs were estimated by ESI. Non-EPC Costs include project management and oversight (both internal and external services), inspections and testing, environmental permitting, pursuing regulatory approvals, temporary facilities and supplies, as well as AFUDC.

Q19. WHAT KINDS OF COSTS ARE INCLUDED IN THE EPC COST ITEM LISTED ABOVE?

A. EPC Costs include costs that will be incurred by CB&I and billed to the Company in the performance of the EPC agreement, including the following:

1. Engineered equipment, including the combustion turbine generator, generator step-up transformers, and auxiliary transformers;

2. Home office engineering and construction management services, including procurement, project controls, scheduling, and progress tracking;

3. Supervisory and administrative staffs at the construction site;

4. Craft laborers (such as welders, electricians, and pipefitters);

5. Construction materials (copper, steel, concrete, etc.) used by both CB&I and subcontractors;

6. Subcontractors;

7. The indirect construction costs that support the construction project (such as scaffolding, administrative offices, or safety equipment);

8. Sales taxes born by CB&I on consumables; and

9. Labor and materials associated with the dedicated start-up and commissioning teams.

Q20. WHAT COSTS ARE INCLUDED IN THE NON-EPC COST ESTIMATE?

A. Costs included in the Non-EPC Cost estimate will be incurred by the Company directly and include:

Other Vendors and Expenses: There is a wide range of services captured in the Other Vendors category, and include expenses such as contract personnel on the project management team, rental of temporary office trailers, construction power, environmental permitting services, the cost of permit applications, site inspections and surveys, transmission studies, gas pipeline charges during the construction period, gas used during commissioning, miscellaneous consumables related to safety and office supplies used during project execution, consultant fees, non-EPC CB&I costs, etc.

Entergy Project Management: Project management costs include internal labor and third party costs for activities such as project oversight and environmental permitting. Construction management includes internal and third-party personnel to manage any agreements to engineer, procure, and construct the project.

Indirect Loaders: This category includes capital suspense estimated at two percent of all capital costs and a variable benefits loader. All other payroll loaders are included in the direct costs of the other categories.

Regulatory: This category includes an estimate of the internal and external costs associated with obtaining Council certification of the Project.

Transmission Interconnection to Switchyard: The amount in this category was based upon the transmission design group's estimate for interconnection to the 115 kV transmission system, which includes the need for some new transmission towers on or near the plant site.

Project Contingency: This is a general contingency estimate of approximately five percent of the total Project cost estimate to allow for circumstances that could affect the cost of the Project which are currently unidentified or uncertain and could include:

- The discovery of facts currently unknown that affect the Project and that are the responsibility of the Company. Examples include: the discovery of unknown underground obstructions, additional fuel supply infrastructure costs or unidentified repairs to existing facilities to be reused, such as the cooling water intake structure;

- Circumstances beyond the control of either the Company or CB&I that affect the cost of the Project, such as damages and delays from significant weather events;

- Changes in laws or regulation that affect the cost of the Project; and

- Delays in obtaining regulatory approval, transmission access, fuel supply, or permits and that result in higher costs.

Q21. DOES THE COST ESTIMATE REFLECT COST ESCALATION ADJUSTMENTS AND PROJECT CONTINGENCIES?

A. Yes. The EPC agreement provides a fixed price and fixed schedule duration, provided that Notice to Proceed ("NTP") is issued on or before [redacted] The NTP is not expected to be issued prior to receipt of acceptable approval from the Council. If NTP is not issued by that date, the EPC contract price is subject to escalation. If NTP is not issued by [redacted], the EPC contract price is open to renegotiation. It is also important to note the risk of increased costs for craft labor and *per diem* on the project resulting from the anticipated labor shortage in the Gulf

Coast region due to ongoing and proposed industrial capital investments over the next decade. The EPC agreement contains a craft labor wage and *per diem* true-up mechanism that would adjust the price upon actual wage rates and *per diem* rates as compared to placeholder escalation rates included in the EPC estimate. These provisions are discussed more fully later in my testimony.

Further, the Company included a contingency estimate that addresses the fact that construction projects of the cost magnitude and time duration of NOPS have cost elements that are beyond the reasonable control of the Company and its management. Even with a fixed-price EPC agreement and well-defined scope, experience demonstrates that unpredictable events, such as discovery of unknown site conditions or changes in laws or regulations, can require change orders that will affect project costs. Thus, contingency must be included in the estimate in order to provide a realistic estimate of the ultimate cost to complete the Project. The current Project estimate contains a contingency line item of approximately five percent of the total project costs, which is reasonable for a project of this nature. I describe risks to the Project and mitigation plans later in my testimony.

Q22. DO YOU BELIEVE THAT THE PROJECT COST ESTIMATE IS A REASONABLE ESTIMATE OF THE COSTS OF NOPS?

A. Yes. The structure of the EPC agreement permits greater confidence in the cost estimate. Additionally, ESI and CB&I spent considerable time developing a detailed scope of work in an effort to reduce the likelihood of change orders that may result in material cost increases. Moreover, the competitive procurement process used to select the EPC contractor, as described above, ensures that EPC Costs (the major component of the overall cost estimate) are competitive.

Q23. SHOULD THE COUNCIL BE AWARE OF ANY ADDITIONAL COSTS THAT WERE NOT INCLUDED IN NOPS' TOTAL COST ESTIMATE?

A. Yes. As more fully discussed in the Direct Testimony of Company witness Charles W. Long, overall costs estimates are subject to the results of the MISO Definitive Planning Phase ("DPP") study process for potential transmission upgrades, which are expected to be supplied by MISO, in part, in February 2017; such upgrades, however, are not expected to be material.

Q24. DOES THE EPC CONTRACT TAKE INTO ACCOUNT THE NECESSARY GAS PRESSURES REQUIRED AT THE MICHOUD LOCATION?

A. Yes. NOPS will be fueled by natural gas delivered through the existing pipeline owned by ENO that previously supplied Michoud Units 2 and 3. Gas compressors will be installed by CB&I as part of the project scope to boost the pressure to the level required by the new unit.

Q25. WHAT ARE SOME OF THE KEY MILESTONES IN THE ESTIMATED PROJECT SCHEDULE?

A. Substantial Completion is expected October 2019. CB&I would receive incentives for early completion and be required to pay liquidated damages for delayed completion. Some of the key milestones in the schedule (assuming certification by Jan. 31, 2017) are:

Milestone	Date
EPC Contract Execution	June 2016
Air Permit issued	Jan 2017
Coastal Use Permit issued	Feb 2017
Regulatory approval – w/ New Orleans City Council	Jan 2017
Notice to Proceed	Feb 2017
Turbine Purchase Order (critical milestone to achieve on time Commercial Operations date)	Feb 2017
Turbine delivery	Aug 2018

Q26. WHAT IS THE EXPECTED TIMING OF THE SPENDING AND FINANCIAL COMMITMENTS ASSOCIATED WITH NOPS?

A. The following HSPM graph depicts the Project's projected cash flow and cancellation commitments:

HIGHLY SENSITIVE PROTECTED MATERIAL

[redacted]

Q27. WHY IS IT IMPORTANT TO OBTAIN TIMELY REGULATORY APPROVALS?

A. As described by Company witnesses Charles Rice and Shauna Lovorn-Marriage, the Company needs reasonable assurance from the Council that construction of NOPS is in the public interest prior to spending several hundred million dollars to construct a plant to serve its customers. Accordingly, the Company does not intend to issue NTP under the EPC Agreement without certification from the Council that undertaking NOPS serves the public interest. The timing of NOPS approval is critical. If Council approval is not obtained prior to [redacted], price escalations will occur in accordance with the terms of the EPC agreement and result in a day-for-day slip of the in-service date. Price escalation will be limited per the terms of the agreement as long as NTP is issued on or before [redacted]. After [redacted], CB&I has the right to renegotiate the price of the EPC contract.

Q28. WHAT DOES THE COMPANY CONSIDER TIMELY REGULATORY APPROVAL?

A. The current schedule is based on the expectation that the Company will have received acceptable approval from the Council by January 31, 2017. Substantial completion is expected to take approximately 31 months following NTP, which is expected to be issued in February 2017.

Q29. ARE THERE BENEFITS TO ISSUANCE OF NTP PRIOR TO FEBRUARY 2017 IF EARLIER APPROVAL IS OBTAINED?

A. Yes. An earlier NTP would potentially allow the unit to be brought on-line prior to October 2019 and potentially allow customers to begin receiving the benefits from this CT earlier. This would also shorten the period over which the Company is exposed to craft labor and *per diem* rate escalation risk.

V. <u>**PROJECT MANAGEMENT AND CONTRACTING APPROACH**</u>

Q30. HOW WILL THE COMPANY MANAGE THE NOPS PROJECT?

A. Given the magnitude of this Project and the Company's existing infrastructure for construction and project management, it is appropriate to follow the same structure used for the construction of Ninemile 6 and the proposed method for the St. Charles Power Station ("SCPS"), which is employing the use of an EPC contractor in conjunction with the Company's management team.

The project management approach will follow Entergy's Project Delivery System ("PDS") Policy, Standards and Guidelines in support of driving consistency and certainty in project delivery outcomes. The PDS provides a framework to ensure Entergy's business units consistently and effectively develop and implement capital Projects. The PDS establishes a Stage Gate Process ("SGP") approach as a single and comprehensive framework for project development, planning, and execution. The SGP provides a roadmap of key deliverables and decisions that need to be sequentially completed to promote consistent, reliable, and high-quality project outcomes. Additionally, the SGP also prescribes a continuous systematic evaluation of the project organization, scope, and maturity of project management deliverables that helps ensure projects are successfully executed. This occurs through a series of independent Gate Reviews/Assessment and Approvals.

Q31. WHAT IS AN EPC CONTRACTOR?

A. EPC is an acronym for Engineer, Procure and Construct and is used to refer to the single-source engineering, procurement, and construction of large projects, and often is used to describe a contractor that performs that function for the ultimate project owner.

Q32. WHY IS THE COMPANY USING AN EPC CONTRACTOR?

A. A construction project like NOPS is a substantial undertaking, and the Company does not have the in-house capability necessary to execute the engineering, procurement and construction for such a project. The use of an EPC contractor who can perform all of these functions under a single contract is cost effective and common within the power industry for such projects.

Q33. IS THERE A SINGLE COMMON FORM OF EPC CONTRACT?

A. No, there are several types of EPC contracting approaches, and the suitability or desirability of each depends largely on the type of project. From an owner's perspective, fixed-price contracts are preferred because of the certainty they provide to a project's overall cost. When a project's scope is uncertain and likely to vary, however, EPC providers will either refuse to contract on a fixed-price basis or perhaps agree to do so in exchange for a significant risk premium added to the fixed price. By contrast, when a project entails a well-defined scope of work and presents an acceptable risk of material changes in scope, EPC providers are more willing to contract on a fixed price basis without charging a significant risk premium.

Q34. WHAT EPC CONTRACTING STRATEGY WILL BE UTILIZED FOR NOPS?

A. The Company was able to negotiate a fixed-price (with exceptions), fixed-schedule form of contract with CB&I that reflects a detailed scope of work. If NTP is issued after [redacted], escalation will apply pursuant to well-defined terms in the

EPC agreement.[7] Only if NTP is issued after [redacted] will the full price be subject to renegotiation instead of contractual escalation. The contractor must complete construction within 31 months (1 month ahead of the planned in-service date) of receiving NTP or else pay daily liquidated damages as defined in the agreement. The contractor also has the opportunity to earn incentives if the Project is completed before the required date.

Q35. WHY DID THE COMPANY ELECT TO USE A FIXED-PRICE FORM OF EPC CONTRACT?

A. The EPC strategy used by the Company is expected to yield the lowest reasonable cost with an adequate level of risk mitigation when the project site can accommodate a standard CT design and there is a minimal amount of retrofit into an existing site.

Q36. HOW DOES THIS FORM OF EPC CONTRACT COMPARE TO THE EPC CONTRACT UTILIZED BY ELL FOR THE CONSTRUCTION OF NINEMILE 6?

A. The EPC contract with CB&I for the NOPS has very similar Terms and Conditions as the EPC contract for Ninemile 6 and SCPS. All three contracts are a fixed-price, date-certain form of contracts. Schedule duration is driven in both cases by the issuance of NTP and with escalation provisions if the NTP is delayed and subject to renegotiation if NTP not issued by a certain date. The contracts have schedule incentives and liquidated damages capped at [redacted]% of the EPC contract value, respectively; and an overall aggregate monetary liability capped at [redacted]% of the total

[7] I discuss craft labor escalation later in my testimony.

EPC contract value. The contracts allow the owner to suspend or terminate for convenience.

The NOPS contract is consistent with the SCPS contract in that both include a craft labor escalation provision with a true-up mechanism, which differs from The Ninemile 6 contract. As discussed more fully below, this mechanism will adjust the EPC contract value if craft labor and *per diem* escalation is higher or lower than what was assumed in the EPC price (*i.e.*, increase if labor costs rise, or decreases if labor costs fall). Another difference in the two contracts is improved (higher) performance liquidated damages for the NOPS agreement as shown in the table below.

HIGHLY SENSITIVE PROTECTED MATERIAL

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Q37. WHAT WORK WILL CB&I PERFORM AS THE EPC CONTRACTOR?

A. Under the fixed price EPC contract structure, CB&I will act as an independent contractor with respect to the engineering, procurement, and construction services defined in the scope of work. CB&I also will procure the combustion turbine. Firm, fixed prices for this equipment are included in CB&I's fixed price and are subject to escalation only at the rates specified in the EPC agreement, if FNTP is not provided by [redacted]. CB&I will provide a "wrap" (*i.e.*, guarantee) of the commitments on schedule and performance for the entire Project, providing for risk mitigation if there are delays or performance shortfalls. CB&I's procurement of this equipment will allow it full coordination and scheduling of the original equipment manufacturers in order to meet the fixed schedule provided in the agreement.

Q38. HAS THE COMPANY AND CB&I AGREED UPON THE TERMS OF AN EPC AGREEMENT?

A. No. The parties are in the final stages of executing the EPC agreement. A summary of the expected term, however, has been attached as HSPM Exhibit JEL-4. The execution of the final EPC agreement is expected to occur within the next month, and the Company will supply the final version of the agreement once executed. Construction under the EPC will not commence until CB&I receives notice to proceed from the Company, as discussed above.

VI. <u>CONSTRUCTION RISK MANAGEMENT AND MITIGATION</u>

Q39. IS IT IMPORTANT TO HAVE PLANS IN PLACE TO MANAGE AND MITIGATE THE POTENTIAL RISKS ASSOCIATED WITH NOPS?

A. Yes. NOPS represents a substantial capital investment, and it needs to be well managed. Good management includes proper consideration of the risks that can be reasonably foreseen and the development of a plan to reasonably manage and mitigate those risks. Good project management should not seek to eliminate all potential risks irrespective of the costs to do so, but instead should reasonably manage those risks considering the probability of occurrence, potential magnitude of impact, and cost to mitigate.

Q40. HOW DO THE KEY RISKS AFFECT THE PROJECT'S SCHEDULE AND PROJECTED COSTS?

A. The fixed-price structure and well-defined scope of work are expected to minimize the effect these key risks may have on project costs. The Company developed mitigation plans and included a contingency in the project cost estimate that is thought to be reasonably sufficient to mitigate those risks identified. Delays in receiving regulatory approvals or the required permits beyond the dates assumed in the project schedule will increase total costs and result in a delayed in-service date. The project schedule has been developed by optimizing the sequence of activities to produce the shortest practical schedule at the lowest reasonable cost. The schedule has a built-in contingency for critical path activities that will help mitigate short delays.

Q41. IS THE CONTINGENCY REFLECTED IN THE PROJECT COST ESTIMATE ADEQUATE TO COVER ALL RISKS THAT COULD INCREASE COST?

A. No, and that is not the purpose of contingency funds in project management. Contingency is used to reasonably mitigate unplanned increases in project cost, whether caused by known risks or unforeseen risks. It recognizes that large construction projects that span several years can be adversely affected by events beyond the utility's control. ESI used a Monte Carlo simulation to determine the level of contingency that would provide a reasonable level of mitigation of known and unknown risks, but it is possible that some of these risks, if realized, could cause cost increases beyond the contingency included in the cost estimate. The Company does not retain any unused project contingency.

Q42. CAN YOU DISCUSS SOME OF THE KEY RISKS UNDER THE EPC CONTRACT?

A. Yes. While the EPC contract with CB&I provides for a fixed price and fixed schedule, any fixed-price contract presents a risk of price increases through change orders and extra work claims. This risk has been mitigated to the extent possible by broadly defining the scope of work assigned to CB&I as including everything necessary to complete the Project that meets the specification and performance requirements, except for items expressly stated in the scope document to be the Company's responsibility. The EPC contract also contains favorable change order provisions that will enable the Company to direct CB&I to proceed with a change order as to which there is a good faith dispute between the parties, with the dispute over price impact to be resolved in arrears. This will protect the Company and its customers from the possibility that the EPC contractor would threaten to delay work until change order disputes are resolved to its satisfaction. Further, CB&I must notify the Company before making any changes required by force majeure events or changes in laws, and must document such changes and the resulting impacts before being entitled to any schedule relief, increase in the fixed price, or additional reimbursement. A discussion of other construction risks, mitigation, and allocation is contained on HSPM Exhibit JEL-5.

Finally, potential wage rate escalation on craft labor and *per diem* is expected to be a significant risk as a result of the anticipated labor shortage in the Gulf Coast region due to ongoing and proposed industrial capital investments over the next decade. To address this risk, the EPC agreement contains a craft labor wage and *per diem* true-up mechanism that would adjust the price twice during the course of the agreement based upon actual wage rates and *per diem* rates.

Q43. PLEASE ELABORATE ON THE CRAFT LABOR PROVISIONS CONTAINED IN THE EPC AGREEMENT.

A. Under the terms of the agreement, CB&I has agreed to assume productivity risk associated with craft labor (*i.e.*, man-hour estimates). CB&I has also agreed to assume subcontractors' craft labor wage escalation risk, as well as that of engineering and project management labor.

The EPC agreement pricing includes a total of $[redacted] million for direct and indirect labor and a total of $[redacted] million labor *per diem* for direct and indirect craft labor *per diem* as placeholders in the EPC fixed price cost.[8] The labor estimate accounts for wage rate escalation at [redacted]% per year and *per diem* escalation at [redacted]% per year. The direct and indirect craft will be itemized into multiple craft personnel categories; the direct and indirect craft wages (and the associated wage rate escalation

[8] Direct craft labor refers to craft laborers that are directly involved in the construction of the permanent plant (*i.e*., pipefitters, welders). On the other hand, indirect craft labor refers to craft laborers who are indirectly involved in the construction of the permanent plant (*i.e.*, scaffolding, support personnel).

placeholder) will be itemized by year and by personnel category across the construction period as estimated by the resource-loaded construction schedule. Similarly, the placeholder for *per diem* (and the associated *per diem* escalation placeholder) will be allocated by year as estimated by the resource-loaded schedule. These placeholders will be trued-up twice throughout the construction process and a third time at substation completion.

The true up amount will be upon completion of the following events:

- 6 months after site mobilization milestone
- 12 months after site mobilization and substantial completion milestones

At the true-up at substantial completion, a determination of expected labor costs after substantial completion shall be made and forecasted true-ups shall be made using the same methodology as was used for previous milestone true ups.

For each of these true-up exercises, the actual CB&I craft wages and *per diem* escalation for the project period in review would be compared to the amount of wage rate and *per diem* escalation included in the EPC fixed price for the same period. Should the wage and *per diem* escalation exceed the escalation assumptions in the EPC fixed contract price for the period, the Company would owe CB&I the increase. In other words, in order for the Company to owe CB&I for an increase, actual craft labor and *per diem* rates would need to exceed the escalation that CB&I already built into the contract based on market trends and historic data. Should the wage and *per diem* escalation be less than the escalation assumptions in the EPC fixed contract price for the period, CB&I would return the difference to the Company. CB&I is required to notify the Company prior to making wage and *per diem* adjustments.

Moreover, an additional disincentive for CB&I to arbitrarily increase wages and/or *per diem* on the Project is the market forces effect on CB&I's other projects in the Gulf Coast region. In other words, should the wage and *per diem* rates for NOPS become misaligned with the market, CB&I's other projects would be negatively affected, as higher wages would attract craft labor from other CB&I projects, increasing CB&I's costs of doing business. Thus, CB&I is incentivized to follow the market as opposed to setting it. In addition, under the contract, CB&I will provide wage and *per diem* market information that it periodically obtains from area labor surveys and exit interviews to support wage and *per diem* adjustment justification. Details of CB&I's actual wage and *per diem* payments for craft labor will be available for the Company to audit. Certain historical and projected data (details to be negotiated) related to wage and *per diem* rates will be included in CB&I's monthly project report.

Q44. DOES THE EPC AGREEMENT HAVE PROVISIONS THAT MITIGATE RISK RELATING TO CB&I'S PERFORMANCE?

A. Yes. As I discussed earlier, the fixed-price, fixed-duration form of contract, coupled with liquidated damages for late delivery, heat rate, and output provide a measure of protection for customers. Additionally, the EPC agreement requires that CB&I deliver a finished product that meets minimum requirements for performance and to warranty that work for 12 months following substantial completion. The contractor is also required to indemnify owner against claims for bodily injury and third-party property damage.

The EPC agreement establishes a milestone payment structure whereby the contractor will only be paid for the work that has been completed, as verified by the Company. The milestone payments are subject to a cumulative cap with monthly values stated in the contract that protects the Company's cash flow. Additionally, payment retention will be accomplished in two ways: 1) a retention payment to be paid only upon successful demonstration of the milestone for Substantial Completion (equal to [redacted] the contract price less the gas turbine generators plus [redacted] of the gas turbine generators), and 2) there will be an ascending letter of credit that will be equal to [redacted] of the contract value, which will increase in value each month as milestones are paid. After Substantial Completion, the total amount of retention will be reduced to an amount equal to the remaining obligations that will include $[redacted] million in retained payments for successful completion of defined project demonstration and reliability tests. The retention will be reduced as obligations are met with the cash component being reduced last at Final Acceptance.

Q45. WHAT TYPE OF INSURANCE IS INCLUDED IN THE COMPANY'S COSTS ESTIMATE FOR THE NOPS PROJECT?

A. As with the construction of units constructed by other EOCs, such as the Ninemile 6 CCGT, the Company intends to procure insurance prior to the issuance of the Notice to Proceed. The expected coverage will include Builders All Risk ("BAR") and Delay in Startup ("DSU").

Q46. WHAT DOES BAR INSURANCE COVER?

A. BAR is for the benefit of the Company, the contractor and subcontractors of every tier, and covers property damage to the project work from non-excluded perils while it is under construction, from the moment of inland shipment from an original equipment manufacturer and/or supplier until the policy lapses. The limit of liability on the BAR is expected to be roughly equal to the EPC contract value, subject to various deductibles depending on the insured peril.

Q47. WHAT DOES DSU INSURANCE COVER?

A. The DSU insurance covers certain schedule-delay costs resulting from property damage to project Work caused by a non-excluded peril under the BAR insurance. After the deductible period is met, DSU insurance provides coverage for certain costs until project completion is achieved, including AFUDC, owner's costs, and contractors increased site costs. The indemnities under the DSU policy are subject to a monthly maximum as well as an aggregate limit. Although the Company has not yet placed DSU coverage for NOPS, it expects to obtain a maximum monthly indemnity of approximately $3 million and maximum indemnity of $52 million for a premium of approximately $415,000**.**

Q48. WOULD IT BE POSSIBLE FOR THE COMPNANY TO TAKE ADDITIONAL STEPS TO PROCURE PROTECTIONS AGAINST POTENTIAL CONTRACTOR PERFORMANCE ISSUES?

A. Yes, another option would be to procure a contractor Performance Bond, which is a surety bond that protects the owner from non-performance and financial exposure should the contractor default; thus, it serves as a promise that the project will be completed.

Q49. WHY DID THE COMPANY DECIDE NOT TO PROCURE A CONTRACTOR PERFORMANCE BOND?

A. There are other more, logical options to manage risks associated with contractor's performance such as a letter of credit ("LOC"), retention, liquidated damages, *etc*.

A performance bond is recommended if there is material risk of contractor insolvency or default. In this case, the Company is utilizing CB&I, which as described in this testimony, is a contractor with a track record of successfully delivering this type of project as well as having the capacity to bond the project if the Company so required, which is an indication of the trust that surety companies have in the contractor.

In order to execute on a performance bond, it first has to be proven that the contractor is at fault, which could require excessive time and effort from all parties. If that effort is successful, then the surety companies decide how to complete the project, either by providing support to the original contractor or utilizing a new contractor. This in turn will cause delays to the project.

As mentioned before, the NOPS EPC agreement with CB&I includes retention, an ascending LOC and both schedule liquidated damages and performance liquidated damages. Obtaining a performance bond would typically increase the cost of a project by 1% - 3% depending on the project and contract specifics, whereas an LOC would only cost about 1% of the LOC amount (in this case, the LOC is [redacted] contract amount), providing a more economical option. Additionally, the EPC agreement also establishes payment retention to be released at time of Substantial Completion, which helps ensures that the contractor completes the Project. Completing the Project on time is mitigated by a date certain contract with schedule liquidated damages, and performance of the plant is mitigated by performance liquidated damages. In the Company's judgment, utilizing a combination of the above mitigation efforts is a reasonable, cost-effective way to manage contractor non-performance risks.

Q50. PLEASE DESCRIBE THE PROJECT MANAGEMENT TEAM IN PLACE TO MANAGE THE PROJECT.

A. A strong leadership team has been selected for NOPS that includes both proven team members from the Ninemile 6 project and new team members.

Gary Dickens, Vice-president Project Management, and the Project Director for Ninemile 6, will retain overall project execution responsibility for this Project. Reporting to Mr. Dickens as the Project Manager for NOPS project will be Brett Seube who joined ESI in early 2015. Mr. Seube has a 13 year background in power plant engineering, project management, and power plant production management.

The NOPS is under the direct oversight of the Project Manager, who has overall responsibility for ensuring that the key objectives of safety, cost, schedule, environmental, and quality are met, and for consulting and communicating with the Project's Executive Steering Committee. The Project Manager will lead a self-build execution team that will manage the processes concerned with construction safety, project budget, cost and schedule control, engineering design review, overall construction site control, start-up and commissioning, documentation control, and progress review.

Overall oversight for the NOPS will be provided by the Executive Steering Committee ("ESC"). The ESC will provide oversight and strategic direction for the Project, monitor and provide direction relating to Project performance, key risks, and value drivers that may affect the Project risk profile, and provides guidance to the Project Management Committee. The Executive Steering Committee acts as liaison between the Project Manager and other executive groups and committees. The self-build commercial team receives additional cross-functional management oversight from the Project Management Committee, which is comprised of key functional area managers and directors that have responsibilities for successful completion of the Project.

Q51. WHAT IS THE COMPANY'S POLICY REGARDING DIVERSE SUBCONTRACTOR PARTICIPATION IN THE CONSTRUTION OF NOPS?

A. As a part of the EPC Agreement, ENO will require CB&I to provide opportunities to small and disadvantaged businesses for participation in any subcontracts and purchase orders let in the performance of its obligations as the EPC contractor. The Company requires CB&I to develop and maintain a list of Diverse Subcontractors and Suppliers that will be supplied to ENO on a quarterly basis. Minority-owned businesses, women-owned businesses, veteran-owned businesses, and disabled-veteran-owned businesses, among others, are included within the meaning of "diverse subcontractors and suppliers." CB&I will be required to submit a plan for utilizing diverse subcontractors and suppliers to ensure such participation in the construction of NOPS.

VII. REQUIRED PERMITS

Q52. PLEASE DESCRIBE THE VARIOUS REGULATORY OVERSIGHT REQUIREMENTS THAT WILL APPLY TO THE PROJECT.

A. NOPS will be subject to permitting and regulatory oversight by the Council, the Louisiana Department of Environmental Quality ("LDEQ"), Louisiana Department of Natural Resources ("LDNR"), United States Environmental Protection Agency ("EPA"), the United States Army Corps of Engineers ("USACE"), Orleans Levee District ("OLD"), and Coastal Protection Restoration Authority ("CPRA"). The LDEQ is primarily responsible for implementing the various federal and state environmental laws applicable to the Project, such as the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and the Louisiana Environmental Quality Act. The EPA is responsible for oversight to ensure that LDEQ properly implements federal law through federally enforceable state implementation plans, regulations, and permits. The LDNR, USACE, OLD, and CPRA are responsible for approving construction standards in navigable waterways relating to navigation safety, fill, dredge, and preservation of jurisdictional wetlands and issuance of the coastal use permit. All of the environmental issues associated with the construction and operation of the NOPS would be subject to regulatory requirements imposed and administered by LDEQ, EPA, USACE, OLD, CPRA, and LDNR in consultation with other state and federal agencies, as required.

A. Air Quality Permits

Q53. WHAT ARE THE PERMITTING REQUIREMENTS ASSOCIATED WITH AIR EMISSIONS FROM THE PROJECT?

A. Electric generation units are heavily regulated under the federal Clean Air Act. NOPS will be subject to multiple federal air regulations that are administered chiefly by LDEQ with EPA oversight. In particular, the Project will be subject to:

- National Ambient Air Quality Standards ("NAAQS") and Prevention of Significant Deterioration ("PSD") rules;
- the federal New Source Performance Standards ("NSPS") associated with industrial-commercial-institutional steam generating units, stationary combustion turbines, and stationary compression ignition or reciprocating internal combustion engines;
- federal requirements associated with hazardous air pollutants; and
- other regulatory requirements associated with air emissions, including continuous monitoring, emissions market allowance obligations, and greenhouse gas emission regulations.

The Company will obtain a Title V (Part 70) Operation Permit and an Acid Rain Permit for the NOPS project encompassing each of the requirements listed above, issued by the LDEQ. A PSD Air Permit will not be required because this type of permit is triggered by an addition or increase of total potential emissions. To the contrary, the allowed emissions from the existing Michoud units (which have been deactivated) were much greater that the emissions to be allowed from NOPS; therefore, the project reflects an overall decrease in emissions from what is currently permitted.

Q54. WHAT REGULATIONS AFFECTED ENO'S SELCETION OF EMISSION CONTROL TECHNOLOGY FOR THE PROJECT?

A. The selection of emission control devices for NOPS were driven by numerous Federal Requirements including New Source Performance Standards ("NSPS"), National Emission Standards for Hazardous Air Pollutants ("NESHAP"), Acid Rain Program ("ARP"), and Cross-State Air Pollution Rule ("CSAPR"). NOPS will employ dry low NOx combustion controls on the Gas turbine to achieve the emission rates as defined in the Federal Regulations.

In summary, the Company has evaluated control technology performance and costs and selected controls that will meet federal standards for all affected pollutants (including greenhouse gas pollutants). The selected controls were submitted to the LDEQ in the minor modification to the existing Title V Permit for the Michoud Electric Generating Plant permit application that was submitted for the NOPS on March 18, 2016 and is pending approval by the LDEQ and EPA.

Q55. IS THERE ANY OTHER EMISSIONS-RELATED INFORMATION OF WHICH THE COUNCIL SHOULD BE AWARE CONCERNING NOPS?

A. Yes. NOPS will produce significantly lower emission levels than the units previously in operation at the Michoud site. This results from several factors. NOPS will use newer, more efficient technology than the deactivated units. NOPS is also a much smaller machine than the deactivated units and will be permitted to operate much less than those units. Indeed, the NSPS, which the EPA developed pursuant to the Clean Air Act and can be found at 40 CFR Part 60, will limit the capacity factor of NOPS, on a three-year rolling-average basis, to the percentage equal to the tested efficiency for the unit.

B. Water Quality

Q56. WHAT WATER QUALITY REGULATIONS WILL APPLY TO THE PROJECT?

A. Like the Clean Air Act, the Clean Water Act also is now administered by the LDEQ. Water discharged from an industrial operation into waters of the State of Louisiana must obtain a discharge permit under the Louisiana Pollution Discharge Elimination System ("LPDES"). The LPDES permit is the state counterpart to the Clean Water Act's National Pollutant Discharge Elimination System permit ("NPDES"). These permits require treatment or management of water to specific water quality levels prior to or during discharge into a stream or waterway. An LPDES modification application incorporating the NOPS discharges into the current Michoud facility permit will be submitted to the LDEQ in 1st quarter of 2018 and will proceed through the LPDES program. The LDEQ has been delegated enforcement and permitting authority for the LPDES program by EPA.

Q57. WHAT OTHER WATER QUALITY REQUIREMENTS MAY BE APPLICABLE TO NOPS?

A. A construction storm water discharge permit from the LDEQ to authorize storm water discharges from the construction area during construction of NOPS will also need to be obtained. A construction Storm Water Pollution Prevention Plan (SWPPP) must also be developed and implemented.

Q58. HOW DOES THE COMPANY PROPOSE TO ADDRESS POTENTIAL WATER QUALITY EFFECTS?

A. The LPDES permitting process is predicated on the requirement that discharges from a permitted facility must be protective of the State's water quality standards. An LPDES permit cannot be issued if it would allow a facility to cause or contribute to violations of water quality standards. The Michoud facility operates under a valid LPDES permit and will continue to operate under a renewed/modified LPDES permit upon issuance which will incorporate all discharges from the NOPS. The issuance of this permit, and ENO's continued compliance, will minimize any water quality impacts. The NOPS facility is being designed in accordance with all water discharge regulatory requirements.

Q59. SHOULD THE COUNCIL BE AWARE OF ANY OTHER INFORMATION CONCERNING WATER QUALITY OR WATER USE RELATED TO NOPS?

A. Yes. Although ENO does not believe any impacts resulted from groundwater usage by the deactivated Michoud units, the Council should be aware that NOPS will result in a substantial decrease in the capacity for groundwater usage when compared to the recently deactivated units. For the deactivated Michoud units, the Company submitted reports concerning groundwater to the U.S. Geological Survey ("USGS") on a quarterly basis, which identified the maximum possible daily usage of groundwater at the site (the largest amount that could be withdrawn by the pumps) at a rate of 10.87 million gallons per day ("GPD"). This figure did not reflect actual groundwater usage at the deactivated units (a smaller number) as groundwater usage for those units was not measured. Comparing the rate reported to the USGS to the absolute maximum possible groundwater usage rates for the NOPS shows a reduction of 90% in comparison to the deactivated Michoud units. Moreover, the maximum expected rate of groundwater usage for NOPS is substantially lower than the maximum possible rate of usage for NOPS. Comparing the maximum expected groundwater usage for NOPS to the reported rate for the deactivated units shows that NOPS will use groundwater at a rate of less than 1% of the rate reported for the deactivated Michoud units, a reduction of approximately 99%.

C. Other Issues

Q60. WHAT OTHER ENVIRONMENTAL ISSUES WITH RESPECT TO NOPS HAVE BEEN ANALYZED?

A. The Company has analyzed information regarding potential effect upon archaeological and historical resources and to threatened and endangered species. The use of the existing Michoud site offers significant environmental advantages over greenfield development in these areas, and no significant issues have been identified.

Q61. WHAT USACE PERMITTING MAY BE APPLICABLE TO THE PROJECT?

A. The Project is located within the Louisiana Coastal Zone and projects affecting jurisdictional waters in the Louisiana Coastal Zone require a joint Coastal Use Permit/Clean Water Act Section 404 permit, and projects in navigable waters that may have an effect on navigation require a Section 10 permit under the Rivers and Harbors Act. The Company has evaluated the project area for its effect on jurisdictional wetlands and work in the Coastal Zone and is in the process of submitting the required joint permit application to the LDNR and USACE. A Request for a Wetland determination from USACE was submitted on October 22, 2015. It is anticipated that the USACE will issue a Jurisdictional Determination, which identifies those wetland areas and waters of the United States that the USACE will take jurisdiction over and must undergo permitting action if impacted by Project construction during the 2^{nd} quarter 2016. The Company has identified the following permits as necessary for the construction of the proposed Project and associated elements:

- LDNR Coastal Use Permit ("CUP")
- USACE Section 404 Permit
- LDEQ Water Quality Certification ("WQC") (only required if individual Section 404 permit is issued and not required if deemed exempt or issued a general permit.
- Orleans Levee District Permit ("OLD")

A CUP or waiver will be required for activities within the Louisiana Coastal Zone. A Section 404 permit is required to place fill material into wetlands or "waters of the United States." A WQC, or waiver or exemption of the same, is required to demonstrate that the placement of fill material and the construction and operation of the facility will not violate the water quality standards of Louisiana. An OLD Permit would be required for work within 300 feet of the centerline of the hurricane protection system (levee/floodwall) on the Mississippi River Gulf Outlet.

Q62. WILL THE NOPS UNREASONABLY IMPAIR VISIBILITY OR VEGETATION?

A. No. Since the project does not trigger Prevention of Significant Deterioration (PSD), the project is not required to provide National Ambient Air Quality Standards (NAAQS) air dispersion modeling or Class I Area Analysis.

Q63. WHAT IS THE STATUS OF THE PERMITS FOR THE PROJECT?

A. The air permit application for the NOPS was submitted to the LDEQ on March 10, 2016 and the Expedited Permitting Processing Requests was approved on March 21, 2016 and the minor modification application has been assigned to an LDEQ Permit Writer. The LDEQ is currently reviewing the application. The LDEQ will complete the review of the application and issue a revised Title V permit. It is anticipated that the revised Title V Permit will be issued in 3rd Qtr 2016.

As discussed above, the existing Michoud facility currently operates under an LPDES permit issued by the LDEQ. An application for renewal of the LPDES permit will be submitted to the LDEQ for renewal as an LPDES permit under the now-approved state program, in the first quarter of 2018.

The Company has evaluated the project area for its effect on jurisdictional wetlands and work in the Coastal Zone. A Jurisdictional Determination was received from the USACE on May 5, 2016 and the required joint permit application to the LDNR and USACE was submitted on May 13, 2016 and is currently under review.

Q64. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF TEXAS

COUNTY OF Montgomery

NOW BEFORE ME, the undersigned authority, personally came and appeared, **JONATHAN E. LONG**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Jonathan E. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 9th DAY OF JUNE, 2016

Angela Stripling

NOTARY PUBLIC

My commission expires: May 11, 2017

ANGELA STRIPLING
Notary Public, State of Texas
My Commission Expires
May 11, 2017

NOTARY PUBLIC STATE OF TEXAS


CT LOCATION
© 2016 Google


New Orleans Power Station
Entergy HQ
Chalmette
Belle Chasse
New Orleans
Metairie
Ninemile 6
Woodmere
Westwego
Kenner
St. Charles
Waterford 3
Luling
Laplace
Google earth
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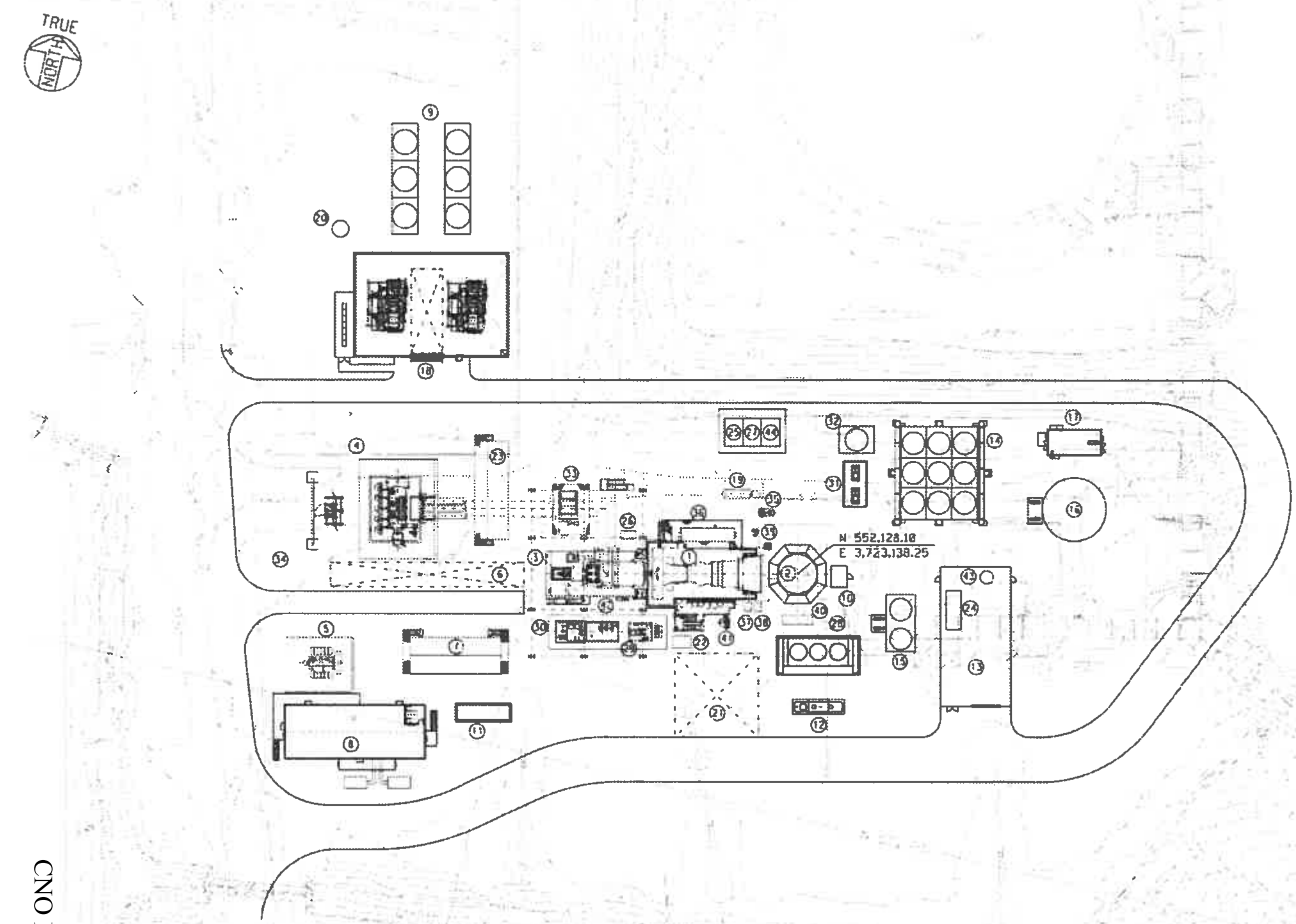
ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	MHPSA 501GAC GT	24	IA/SA COMPRESSORS & RECEIVER
2	EXHAUST STACK	25	HYDROGEN STORAGE AREA
3	INLET AIR FILTER	26	EVAPORATE COOLING BLOWDOWN SUMP/PUMPS
4	GENERATOR STEP UP TRANSFORMER	27	CO2 STORAGE AREA
5	UNIT AUXILIARY TRANSFORMER	28	GT COOLING AIR COOLER
6	GENERATOR ROTOR REMOVAL SPACE	29	GT CONTROL OIL UNIT
7	GT CONTROL PACKAGE	30	GT LUBE OIL TANK, RESERVOIR COOLERS & ACCUMULATOR
8	ELECTRICAL EQUIPMENT BUILDING		
9	COMPRESSOR COOLING AIR COOLER	31	CLOSED COOLING WATER PUMPS
10	CEMS ENCLOSURE	32	CLOSED COOLING WATER HEAD TANK
11	EMERGENCY DIESEL GENERATOR	33	GENERATOR CIRCUIT BREAKER
12	OILY WATER SEPARATOR	34	HIGH SIDE BREAKER & TOWER
13	WATER TREATMENT BUILDING	35	GT CASING COOLING FAN
14	CLOSED COOLING WATER HEAT EXCHANGER	36	GT FUEL GAS UNIT
15	PERMEATE WATER STORAGE TANKS	37	GT WATER WASH DRAIN PIT
16	SERVICE/FIRE WATER STORAGE TANK	38	GT DRAINS SUMP/PUMP
17	FIRE WATER PUMP HOUSE	39	GT FUEL GAS LAST CHANCE FILTER
18	GAS COMPRESSOR BUILDING	40	GT FLOW GAS FLOW METER
19	CO2 FIRE FIGHTING FOR CT	41	TURBINE COOLING AIR FILTER
20	GAS SCRUBBER EQUIPMENT	42	GT LOOP SEAL TANK
21	CRANE/MAINTENANCE AREA	43	DEMIN WATER TANK
22	WATER WASH SKID	44	NITROGEN STORAGE AREA
23	GTG EXC. SFC PACKAGE & TRANSFORMERS		



ENTERGY
NEW ORLEANS PS
UNIT 1

PLOT PLAN

SCALE	CLIENT JOB NUMBER	UNIT JOB NUMBER
1"=30'		151248

DRAWING NUMBER	REV NO
151248-P-PP-001	H

Exhibit JEL-3
CNO Docket No. UD-16-___
Page 1 of 1

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW	**)**	
ORLEANS, INC. FOR APPROVAL TO	**)**	
CONSTRUCT NEW ORLEANS POWER	**)**	**DOCKET NO. UD-________**
STATION AND REQUEST FOR COST	**)**	
RECOVERY AND TIMELY RELIEF	**)**	

EXHIBIT JEL-4

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT JEL-5

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-______**

DIRECT TESTIMONY

OF

CHARLES W. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JUNE 2016

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Charles W. Long. I am employed by Entergy Services, Inc. ("ESI")[1] as Director, Transmission Planning. My business address is 6540 Watkins Drive, Jackson, Mississippi 39213.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council of the City of New Orleans ("CNO" or the "Council") on behalf of ENO in support of the construction of New Orleans Power Station (the "Project" or "NOPS"), a proposed advanced combustion turbine ("CT") facility that is proposed to be located at ENO's Michoud site in New Orleans, Louisiana.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I graduated in 1991 from the University of Alabama in Tuscaloosa with a Bachelor of Science degree in Electrical Engineering. I began my professional career in 1992 with Louisiana Power & Light Company (now ELL) as a system protection engineer, remaining in that capacity until 1996. In 1996, I moved into transmission operations

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[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans, Inc. ("ENO or the "Company"), and Entergy Texas, Inc. ("ETI").

planning within ESI, where I worked until 2000. In 2000, I became the substation supervisor in Baton Rouge, Louisiana, for Entergy Gulf States, Inc. (now ELL). In 2006, I assumed the role of Manager, Transmission Planning with planning responsibility for transmission facilities for EAI and EMI.

I was promoted to my current position in April of 2012. As the Director of Transmission Planning, I am responsible for overseeing the development of proposals for the expansion of, and improvements to, the transmission systems of the EOCs, including those of the Company. Specifically, my responsibilities include providing leadership and guidance to a staff of managers and engineers engaged in all aspects of long-term transmission planning, including the development of projects and plans designed to (1) ensure that the transmission systems of the EOCs remain in compliance with North American Electric Reliability Corporation ("NERC") reliability standards governing transmission planning, as well as local planning criteria, and (2) deliver energy to the customers of the Company and the other EOCs at the lowest reasonable cost. I have over twenty years of experience in transmission system planning, operations, and maintenance, and I am a registered professional engineer in the state of Louisiana. A list of my prior testimony is attached as Exhibit CWL-1.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the Company's Application in this proceeding, which seeks, among other things, approval to proceed with the construction of NOPS, a CT with a nominal capacity[2] of 226 MW, at summer conditions. My testimony first describes the unique operational reliability-related characteristics of the Downstream of Gypsy ("DSG") region of the power system. To begin, it should be noted that New Orleans is located in DSG; and, accordingly, reliability in the City is greatly affected by reliability within the region. My testimony also discusses the transmission-related benefits that NOPS is expected to produce. Finally, my testimony discusses the process that MISO uses to identify transmission upgrades that may be necessary for the integration of NOPS into the electric grid.

II. TRANSMISSION RELIABILITY BENEFITS

Q5. PLEASE DESCRIBE THE LOCATION OF NOPS ON THE ELECTRIC GRID.

A. New Orleans is located in the DSG region, which has unique geographical limitations (*i.e.*, it is largely surrounded by water) and contains highly concentrated electrical loads. This geography limits the amount of transmission facilities available to serve DSG, and accordingly, New Orleans; and makes the region reliant upon local generation to maintain reliable service. Further, as described by Company witness Seth E. Cureington, following the recent deactivation of Michoud Units 2 and 3, the four units that ENO currently depends on for reliability in DSG are all located outside of Orleans Parish. It should also be noted that an area such as DSG, which is heavily

[2] Nominal capacity refers to the nameplate capacity of the unit at which the unit can be expected to produce a sustained output at full-load. However, the actual output of a unit depends on a number of factors that vary from unit to unit and site to site.

reliant on local generation to maintain reliability and which has limited import capability, is generally referred to as a load pocket.

The electric load in DSG is currently served, in part, by the following generators: Ninemile Units 4, 5, and 6 and Buras.

Q6. PLEASE DESCRIBE THE MANNER IN WHICH MISO ENSURES THAT SUFFICIENT GENERATION IS COMMITTED TO MAINTAIN RELIABILITY FOR ENO CUSTOMERS.

A. To ensure reliable operations, Midcontinent Independent System Operator, Inc. ("MISO") often commits local generators based solely on their contribution to reliability. As mentioned, New Orleans is highly dependent upon reliability within the region it is located, DSG, and historically, the simultaneous loss of a generation resource and a transmission element in DSG was often observed to result in voltage and thermal constraints, which cannot be mitigated without the commitment of another local unit. In other words, the commitment of a generator elsewhere in the system outside of DSG was found to be ineffective in mitigating the constraints resulting from the simultaneous loss of a DSG generator and a transmission branch in the DSG footprint. This observation, in conjunction with the fact that many of the legacy DSG generators have long start-up times, led to the imposition of commitment guides to ensure reliable electric service during the simultaneous outage of a transmission branch and a generation resource.

Since ENO integrated into MISO, similar commitment guides were imposed, referred to in the MISO Tariff parlance as Voltage and Local Reliability ("VLR") operating guides. Thus, all DSG units, including Michoud Units 2 and 3 prior to their deactivations, are VLR resources and are committed by MISO to ensure reliability. As discussed more fully below, VLR resources are committed by MISO to ensure that enough capacity exists in the region to maintain reliability despite the fact that another unit inside or outside the region may be more economic from an energy-cost perspective.

Q7. WILL NOPS LIKELY BE INCLUDED IN THE DSG VLR COMMITMENT GUIDE, IF APPROVED?

A. Yes. Based on the Company's understanding of the DSG VLR guide and given that the Michoud Units 2 and 3 were resources that had a VLR role, it is very likely that NOPS will be included in the DSG VLR commitment guide. Thus, NOPS is expected to have a positive impact on local operational and long-term reliability.

Q8. DOES MISO TAKE RELIABILITY INTO ACCOUNT DURING THE UNIT COMMITMENT PROCESS?

A. Yes. MISO uses the Reliability Assessment Commitment ("RAC") process in connection with its generator commitment process to ensure that a sufficient amount of generation is committed to meet load forecasts and operating reserve requirements. In the day-ahead process, once units are committed based on economics for the next operating day, MISO performs the RAC process to determine whether additional resources are needed to maintain reliability in the electric grid. MISO also performs this reliability assessment throughout the operating day using a process referred to as the intra-day RAC, to ensure that reliability is constantly maintained.

MISO also performs a longer-term reliability assessment, performed up to seven days prior to an operating day, which is referred to as the Forward RAC or the Multi-Day RAC, to ensure that resources with long start-up times (longer than can be handled by the ordinary RAC process) may also be committed as necessary to maintain reliability in the electric network. All units that submitted its capacity into MISO's capacity auction are expected to be available for dispatch if they are not experiencing an outage.

Q9. IF NOPS WERE NOT CONSTRUCTED, WOULD THERE BE DEGRADATIONS IN THE RELIABILITY OF THE ELECTRIC SYSTEM IN NEW ORLEANS AND THROUGHOUT DSG?

A. Yes. The Company maintains a plan to ensure compliance with North American Electric Reliability Corporation ("NERC") Reliability Standard TPL-001-4 over a ten-year planning horizon. NOPS has been included in that plan beginning in October 2019. If the unit is not constructed, the Company would be required to re-assess its plan for compliance with NERC standards and alternative plans involving transmission upgrades to avoid reliability challenges over the ten-year planning horizon would be necessary.[3] In other words, the exclusion of NOPS would likely involve the construction of multiple new transmission facilities into the greater New Orleans area, each of which would be difficult and costly to construct given the limited land availability and environmental challenges associated with transmission line construction in that region. For example, NERC TPL-001-4 requires that "the system shall remain stable" and that "cascading and uncontrolled islanding shall not occur."[4] Without NOPS, a "Category P6"[5] event would result in:

- Cascading outages resulting in the loss of the electrical load served from twelve of the fourteen ENO substations operating at 115 kV. This would result in an outage to approximately 49,000 ENO customers and given the nature of the event, the outage could prevail for an extended period of time.
- Multiple transmission lines, totaling more than 30 miles in length, operating well in excess of their thermal capabilities (overloading).
- The need to install additional reactive power resources to prevent voltage instability.

If NOPS is approved and constructed, such transmission projects to address these issues likely will be avoided.

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[3] It should be noted that ELL's proposed construction of St. Charles Power Station in St. Charles Parish, Louisiana has also been factored into the Company's plan for NERC compliance and does not obviate NOPS' role in addressing long-term NERC compliance in DSG.

[4] NERC TPL-001-4; Table 1, Page 8, note a.

[5] NERC TPL-001-4; Table 1, Page 9; A P6 event is the loss of a transmission facility followed by system adjustments, followed by the loss of an additional transmission facility. P6 simulates operational conditions that would occur during a planned (maintenance outage) or unplanned outage to a transmission facility followed by an unplanned outage to an additional transmission element.

Q10. COULD AN EVENT LESS SEVERE THAN A "CATEGORY P6" CONTINGENCY LEAD TO DEGRADATION IN THE TRANSMISSION SYSTEM IF NOPS IS NOT CONSTRUCTED?

A. Yes. Less severe events would lead to local issues that would increase the likelihood of localized load-shedding (outages to customers to prevent system damage). For example, an event involving a short-circuit fault on a substation bus bar, faults involving the failure of circuit breakers, and the simultaneous outage of a generator and a transmission line could result in overloads. Maintaining the existing plan to construct NOPS avoids implementing alternative mitigation measures to address these reliability challenges by placing an efficient quick-start resource in an ideal location. Such alternative measures for these overloads include, for example, an immediate need to rebuild the Curran to Almonaster 230 kV line that is 9 miles in length. If the Company is not able to add NOPS, alternative transmission projects would be necessary to ensure NERC compliance and the reliability of existing ENO customers over the ten-year planning horizon.

Q11. WHAT IS THE COST OF MITIGATING THE DEGRADATIONS IN THE RELIABILITY OF THE ELECTRIC SYSTEM IN THE NEW ORLEANS AREA THAT WOULD RESULT FROM THE NON-APPROVAL OF NOPS?

A. Detailed planning-level cost estimates for transmission upgrades that will mitigate the various reliability constraints that result from the non-approval of NOPS have not yet been developed. However, the cost associated with these transmission upgrades is expected to be tens of millions of dollars.

Q12. WOULD A SMALLER RESOURCE PROVIDE FOR THE NEEDED RELIABILITY IN THE NEW ORLEANS AREA?

A. No. A smaller resource would not completely address the reliability concerns. Virtually the entire 226MW of capacity that is planned for NOPS is needed to completely mitigate the reliability issues described above for the ten-year planning horizon without additional mitigation measures being needed.

Q13. PLEASE EXPLAIN WHY THE TRANSMISSION UPGRADES (MENTIONED ABOVE) WERE NOT IDENTIFIED IN THE ATTACHMENT Y STUDY FOR THE MICHOUD U2 AND U3?[6]

A. While the purpose of MISO's Attachment Y analyses is to identify reliability constraints that will result from the retirement of the generator being studied, the MISO Attachment Y study utilizes a 'filter' in order to screen the reliability constraints that result from the generator retirement. Through this filtering process, MISO identified only those reliability constraints caused by the generator retirement that are immediate and acute. Alternatively, as required by the NERC TPL 001-4 reliability standard requirements, ENO's annual reliability assessments do not employ

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6 See Attachment Y Results for Michoud Units 2 and 3, attached as Exhibit CWL-5.

any such filtering criterion. Instead, ENO's annual reliability assessments identify all reliability issues during the simulation of planning events, or contingencies prescribed by the NERC TPL standard, over a much longer planning horizon.

Additionally, while the Attachment Y analysis performed by MISO covers most of the major contingency categories required by the NERC TPL 001-4 reliability standard, the analyses do not address every requirement of the NERC TPL Standard and thus are not as comprehensive as the Company's annual reliability assessments. Thus, because of the limitations in the Attachment Y process, not all constraints that have been observed by ENO would be expected to have been identified in the Attachment Y studies for Michoud Units 2 and 3.

Q14. PLEASE ALSO EXPLAIN WHY MISO DID NOT IDENTIFY THE NEED FOR NOPS IN THE ATTACHMENT Y STUDY FOR MICHOUD UNITS 2 AND 3?

A. MISO only includes generating resources that have an active Generator Interconnection Agreement ("GIA") with MISO in Attachment Y analyses. Additionally, MISO's Attachment Y study process (at the time of the Michoud Units 2 and 3 retirement studies) requires that only transmission solutions be identified for the valid constraints observed in the Attachment Y analysis. Thus, NOPS could not have been included in the Attachment Y study models because a GIA associated with NOPS has not been signed.

Q15. ARE THERE ANY ADDITIONAL RELIABILITY BENEFITS ASSOCIATED WITH LOCATING NEW GENERATION IN ORLEANS PARISH?

A. Yes. In general, when generating capacity is added to the electric grid, it produces the most transmission-related benefits when located in proximity to the load that it will serve. Locating the proposed NOPS generator at the Michoud site will produce the following benefits:

- Increased load-serving capability in the New Orleans area, which is supportive to economic growth;
- Improved ability to serve existing load reliably by reducing the region's dependence on already strained transmission facilities;
- Increased operational flexibility such that necessary maintenance activities for generation and transmission facilities in the area could be planned more efficiently without incurring operational risk during planned outages;
- Increased reactive power, which would improve stability in the DSG region and would thus avoid potential voltage instability and increasing system efficiency by providing reactive power margins to existing customers and supporting future industrial growth;
- Increased storm restoration benefits, which could help the Company to restore service to customers in a timely manner following a major storm event.

Q16. WHAT ARE THE REACTIVE POWER BENEFITS OF NOPS?

A. Reactive power, which is required to serve loads such as air-conditioning motors and other commercial and industrial facilities, does not travel efficiently across long transmission lines because of the very high reactive losses in all transmission lines. Thus, any incremental reactive power demand in the New Orleans area can most efficiently be met with reactive power sources in close proximity to the load, either through additional static devices such as capacitor banks (which provide only steady-state or slow control of the voltage) or active devices like NOPS which are capable of providing dynamic or fast reactive power to control voltage during and after system disturbances. Moderately to heavily-loaded transmission lines and transformers also consume reactive power. Failure to properly account for reactive power sources to meet additional reactive power needs caused by load growth or contingencies involving transmission facilities or generators in the DSG region may result in sluggish voltage recovery after disturbances on the system. In extreme cases, a severe scarcity of reactive power in the region, after a disturbance (also referred to as a "fault") on the transmission system, may result in the collapse of the voltage on the grid and lead to widespread outages in the region.

The location of NOPS will add a very valuable active source of reactive power that can support the voltage recovery after a fault on the transmission system. Moreover, adding power generation within the region will reduce the need to import power and reduce the overall reactive power demand of the region by reducing the reactive power consumed by transmission lines feeding the region. In sum, a new generation resource in New Orleans will greatly enhance the reactive power capability in the area, decrease reliance on the transmission system to meet energy needs, and will, in turn, increase the reliability and load-serving capability in the area.

Q17. ARE THERE ANY OTHER BENEFITS ASSOCIATED WITH THE INTERCONNECTION OF NOPS IN THE DSG LOAD POCKET?

A. Yes. NOPS also adds a local source of active or "real" power in the DSG load pocket with the ability to start quickly. This can aid in shortening the time to restore service to customers after large scale events such as hurricanes or other natural disasters. For example, if the transmission system experiences extensive damage during a hurricane, which has occurred in the past in the New Orleans area, the ability to import power across the transmission lines may be impaired for many days due to transmission system damage. In such a scenario, local generation units make it possible to locally supply power through a smaller number of relatively short transmission lines which can be repaired more quickly. A unit like the proposed NOPS provides a "starting point" for restoration and allows restorations to occur more quickly than would be possible relying solely on transmission facilities. A local generator, such as NOPS, will also greatly aid in maintaining the integrity of the electric system in the event that a storm severs the electric grid in a manner that creates an electrical island.

In fact, this phenomenon occurred during Hurricane Gustav. After that Hurricane, the greater New Orleans metropolitan area and the industrial corridor southeast of Baton Rouge, Louisiana had dis-integrated from the rest of the country's electrical system, thus operating as an island for 33 hours. Without local generation, every customer in the area would have experienced a complete outage for those 33 hours. The fact that NOPS unit is capable of quick-starting means that even if it were off, it could be quickly brought on line to serve local customers in situations where the transmission system was damaged such that it could not import the power.

Q18. WOULD THE ADDITION OF HIGH VOLTAGE TRANSMISSION LINES TO INCREASE IMPORT CAPABILITY INTO DSG ADDRESS THE RELIABILITY CONCERNS THAT NOPS WILL MITIGATE?

A. No. To begin, attempting to increase the import capability to add more capacity to the DSG area, and thus, New Orleans, will not produce the same reliability benefits discussed above. For example, while it is possible that the new transmission projects, if built to more exacting construction standards, may prove to be more storm resilient, the transmission lines would still only function as a means to transport power from resources outside of the load pocket that have to be able to withstand any impacts from the storm and have headroom (or reserve) available to be able to serve load in the load pocket. By contrast, NOPS will be a source of local generation, capable of serving incremental load independently, without reliance on long transmission lines. Moreover, the area has very swampy and poor soil conditions that tend to increase the costs of construction substantially. There are also many above-ground obstructions and below-ground obstructions in terms of pipelines and facilities to serve plants. Considering these factors, it is very difficult to find a route through the area to add transmission, and it's generally very expensive to do so based on all of these challenges.

Moreover, it should also be noted that, as discussed more fully in the Direct Testimony of Mr. Cureington, market equilibrium in MISO South (the point at which supply, including third-party resources, and demand, including appropriate planning reserves, are in balance) will occur around 2022. MISO has predicted equilibrium to occur sooner for the entire MISO footprint. This means that even if the Company were to invest in constructing transmission to increase the import capability into the region, it is possible there would be no excess capacity available to import long-term.

III. NOPS TRANSMISSION UPGRADES AND <u>OVERVIEW OF MISO INTERCONNECTION PROCESS</u>

Q19. WHAT ARE THE DIFFERENT TYPES OF TRANSMISSION UPGRADES THAT MAY BE REQUIRED FOR NOPS?

A. There are three different categories of upgrades and associated costs that may be identified for an interconnecting generator, such as NOPS:

1. Upgrades required for the interconnection to the switchyard;

2. Upgrades identified by MISO that are necessary to designate the resource as a Network Resource(*i.e.*, for the resource to be granted Network Resource Interconnection Service ("NRIS")); and

3. Upgrades identified by the Transmission Owner ("TO"), in this case the Company, that are necessary to mitigate any violations of NERC Reliability Standards and/or Planning Criteria that are caused by the generator.

Q20. PLEASE DESCRIBE THE FIRST CATEGORY OF UPGRADES THAT MAY BE NECESSARY FOR NOPS, THE UPGRADES REQUIRED FOR INTERCONNECTION TO THE SWITCHYARD.

A. These are transmission upgrades necessary to physically connect the generator to the electrical system. Typically, these upgrades consist of any transmission or distribution-voltage lines or cables necessary to connect the generator step-up transformer with the interconnection substation, circuit breakers and associated switches and any substation yard work that may be required at the interconnecting substation. This electrical infrastructure may be owned and maintained by either the TO or the Generator Owner ("GO"). In this case, the Company is both the TO and GO.

Q21. PLEASE LIST THE UPGRADES NECESSARY FOR INTERCONNECTION TO THE SWITCHYARD FOR NOPS AND ASSOCIATED COST ESTIMATES.

A. For NOPS, a total of $2.3 million in transmission upgrades have been identified as interconnection to the switchyard costs for NOPS. These upgrades will be estimated to a higher degree of accuracy during the Interconnection Facilities Study portion of the Definitive Planning Phase ("DPP") of the MISO interconnection process, which will be discussed in detail later in my testimony.

Q22. NEXT, PLEASE DESCRIBE THE PROCESS USED TO DETERMINE THE SECOND CATEGORY OF UPGRADES, THOSE NECESSARY FOR NRIS SERVICE.

A. Those upgrades are identified through the MISO interconnection process. As shown in my Exhibit CWL-2, the process commences with the submittal of the generator interconnection request by the GO. The interconnection request must be accompanied by the documents and data that constitute the M1 milestone (more fully defined on page 2 of Exhibit CWL-2), along with two different payments, an application fee and a fee to fund the first stage of the process, the Feasibility Study ("FeS").

Next, if all the M1 milestones are met, MISO commences the FeS for the interconnection request. The FeS is an information-only deliverability study performed by considering the resource requesting interconnection in isolation to any other changes on the MISO system and determining whether any transmission constraints would impede the deliverability of this resource to the entire MISO footprint. The FeS concludes with MISO communicating the results of the FeS deliverability study, which consists of transmission constraints, if any, that were observed in the deliverability analysis of the resource. It should be noted that the FeS does not include any information on any transmission upgrades that might be needed to facilitate the first category of transmission upgrades mentioned above, those related to interconnection to the switchyard.

Once the results of the FeS are conveyed to the GO, the GO can then enter the next phase of the study, called the Definitive Planning Phase ("DPP") by submitting the information necessary to fulfill the M2 milestone (more fully defined on page 2 of Exhibit CWL-2) and a payment to fund the DPP study, called the D3 payment. The DPP is only conducted two times a year and, as shown on Exhibit CWL-3, NOPS resource will be entered into the August 3, 2016 DPP cycle.

Q23. WHAT ANALYSES ARE CONDUCTED IN THE DPP PROCESS?

A. The DPP study consists of a two-step process that will result in potential transmission upgrades and associated costs:

1. The System Impact Study ("SIS") & Interconnection Facilities - Facilities Study ("IF-FS"); and

2. Network Upgrade Facilities Study ("NU FS").

Q24. PLEASE EXPLAIN THE FIRST STEP IN THE DPP PROCESS, THE SIS AND THE IF-FS STUDIES.

A. At the outset, it should be noted that because of the limited number of DPP analysis cycles that MISO runs each year, and because these analyses are not done in isolation (the analyses take into account other generators that have requested interconnection and/or NRIS that may impact the constraints and transmission upgrades), MISO batches all of the interconnection requests between two DPP cycles (as well as any interconnection requests entering the DPP after having 'parked' their request following the FeS) together and analyzes the NRIS deliverability of all resources in close proximity together. This means that the generators in the interconnection queue that may have somewhat similar impacts on a particular constraint are considered together by studying their NRIS deliverability to the MISO footprint simultaneously. This deliverability methodology is aimed at ensuring that MISO captures any constraints on the transmission system that might arise if the resources requesting NRIS were to simultaneously provide capacity and energy to the MISO system.[7]

The SIS analysis itself is a deliverability study that considers all of the resources requesting NRIS in a particular DPP cycle while also protecting the NRIS service already granted to existing generators. The deliverability analysis involves the identification of transmission constraints that may result from transferring capacity from the resource to the MISO footprint and, subsequently, if constraints on the transmission system are observed, MISO identifies transmission upgrades required to mitigate the constraints.

MISO typically collaborates with the applicable TO to identify required transmission upgrades. As mentioned above, MISO aggregates resources that, in MISO's opinion, may significantly impact a particular limiting transmission element, and, MISO studies the deliverability of all of those resources in aggregate for that particular limiting element. Once all the upgrades are identified, MISO works with the applicable TO to determine the planning-level cost estimate (typically a Class 5 cost estimate, which has an accuracy between -50% and + 100% of the final cost estimate) for the identified transmission upgrades. Additionally, any replacements of existing circuit breakers that will become under-rated due to the resource

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[7] It should be noted that submission of generation into the DDP is not a commitment to build or interconnect.

interconnection are also identified by MISO in the SIS, working in conjunction with the applicable TO.

The second study within the first step of the DPP process, the IF-FS, is a more detailed analysis of the upgrades necessary to interconnect the resource to the switchyard. As explained earlier, these upgrades are the same upgrades discussed above to interconnect NOPS to the switchyard, but the "FS," or "Facilities Study" designation denotes an analysis wherein the costs of upgrades have been estimated to a high degree of accuracy. Thus, the IF-FS involves the estimation of the cost of upgrades to a higher degree of accuracy. Facilities Studies typically involve the determination of a more precise Class 3 estimate, which has accuracy between -20% to +30% of the final cost estimate of the upgrade(s).

Together, the SIS and the IF-FS constitute the first step in the DPP process and are expected to take up to ninety (90) days to complete (here, November 2016). Upon completion of these two studies, the next step in the DPP process, NU FS, can begin.

Q25. PLEASE EXPLAIN THE SECOND STEP IN THE DPP PROCESS, THE NU FS PORTION.

A. Following the completion of the SIS and IF-FS, MISO requests the applicable TO perform a Facilities Study to refine the planning-level estimates for the transmission upgrades that have been identified in the SIS. Just as with the IF-FS, the NU FS is also generally expected to produce Class 3 cost estimates that have an accuracy of -

20% and +30% of the final project cost estimate. The duration of the NU FS is typically 90 days (here, February 2017) and will result in the final costs to construct the upgrades necessary to grant NRIS being approved by MISO.

Q26. DID MISO COMPLETE A FEASIBILITY STUDY FOR NOPS?

A. Yes, MISO has completed a FeS for the interconnection request for NOPS. CWL-4 contains the results of the FeS for NOPS resource.

Q27. WHAT WERE THE PARAMETERS USED IN THE REFERENCED MISO FEASIBILITY STUDY?

A. As mentioned above, the Summer capacity of the resource entered into the FeS was 226 MW.

Q28. WHAT WERE THE RESULTS OF THE REFERENCED MISO FEASIBILITY STUDY?

A. As shown in Exhibit CWL-4, the results of the FeS indicate that no constraints were observed for the interconnection of NOPS to the electric grid at the Michoud substation.

Q29. ARE THERE ANY FACTORS THAT THE MISO FEASIBILITY STUDY DID NOT CONSIDER?

A. No. No additional factors are currently anticipated to impact the result of the interconnection and NRIS deliverability of NOPS. The Company does not believe that there are any compelling reasons to expect the DPP study for NOPS to produce results that are materially different from that obtained in the FeS for NOPS.

Q30. WHEN IS THE DPP STUDY EXPECTED TO BE COMPLETED BY MISO?

A. As noted above, the Company will enter NOPS into the August 3, 2016 DPP cycle. The Summer capacity that was entered by the Company into the interconnection process (in the FeS) was 226 MW. MISO is expected to analyze the deliverability of 226 MW of NRIS in the August 2016 DPP analysis, which is expected to be complete in February 2017.

Q31. WHAT ACTIONS WILL THE COMPANY TAKE FOLLOWING THE RECEIPT OF THE DPP STUDY?

A. Following the DPP study results, the Company will provide the Council and intervenors the costs, if any, for the NRIS deliverability of NOPS. The Company will also take the necessary steps to sign the Generator Interconnection agreement ("GIA").

Q32. WILL THE REQUIRED UPGRADES FROM THE DPP STUDY BE DEFINITIVE?

A. Yes, the required upgrades provided by MISO in the DPP process are definitive.

Q33. ARE THE COSTS ASSOCIATED WITH THE SECOND CATEGORY OF UPGRADES ASSOCIATED WITH NOPS, THOSE NECESSARY FOR NRIS, INCLUDED IN THE TRANSMISSION COSTS SHOWN IN THE OVERALL COST ESTIMATE PROVIDED IN THIS FILING?

A. No. Since the DPP process has not yet been conducted, the Company has not estimated any costs associated with the NRIS deliverability that will be determined by MISO in the DPP process. To be clear, if any transmission upgrades are identified, such costs would be incremental to the current overall cost estimate for NOPS.

Q34. ARE THE POTENTIAL UPGRADES, IF ANY, EXPECTED TO BE SIGNIFICANT?

A. As mentioned before, each DPP cycle involves the batched deliverability analysis of all interconnection requests received for a particular DPP cycle. This makes the outcome of each DPP cycle analysis potentially unique and difficult to predict because the details of interconnecting resources cannot be anticipated prior to the commencement of the DPP analysis. While the results of the FeS, which involves a stand-alone deliverability analysis (*i.e.*, a capacity transfer analysis from the resource to the MISO footprint, without the effects of any other interconnection requests), indicated no required transmission upgrades, those results are not necessarily indicative of the DPP analysis' results.

Q35. PLEASE EXPLAIN THE DIFFERENCE BETWEEN ENERGY RESOURCE INTERCONNECTION SERVICE ("ERIS") AND NRIS. PLEASE ALSO EXPLAIN WHY THE COMPANY WILL SEEK NRIS FOR NOPS, IN ADDITION TO ERIS.

A. ERIS grants a resource the right to interconnect to the MISO electric grid, inject energy into the system and participate in the Day-Ahead and Real-Time energy markets. However, in order for the resource to be eligible for participation in the Planning Resource Auction ("PRA") and for the resource to be granted Zonal Resource Credits ("ZRC"), the resource is required to have NRIS. Participation in the PRA (also informally referred to as the capacity auction) makes the resource eligible to receive the Auction Clearing Price for capacity in the Local Resource Zone in which the resource is located, if the resource partially or wholly clears the capacity auction.

When the resource requesting interconnection funds the upgrades that are identified in the IF-FS, it is granted ERIS for the number of MW that have been interconnected to the system. When MISO performs the SIS during the DPP process, the SIS may result in three different outcomes:

- No constraints are identified in the NRIS deliverability test: in this case, the resource will also be granted NRIS (without having to fund any other transmission upgrades) for the same amount that it was granted ERIS.
- Some amount of NRIS from the resource is deliverable, but constraints are identified beyond that amount: in this case, the resource would be granted NRIS up to the number of MW for which no constraints were identified in the NRIS deliverability analysis without having to fund any further transmission upgrades. For the resource to be granted any NRIS beyond this MW amount, the upgrades that MISO has identified in the SIS (and subsequently in the NU FS) must be funded for incremental NRIS deliverability.
- No NRIS deliverability is possible (*i.e.*, constraints are identified even for one MW of incremental NRIS): in this case, the resource cannot be granted any NRIS unless the Company chooses to fund the upgrades that MISO has identified in the SIS (and subsequently in the NU FS) for incremental NRIS deliverability.

Q36. FINALLY, PLEASE DESCRIBE THE PROCESS USED TO DETERMINE THE THIRD CATEGORY OF UPGRADES AND ASSOCIATED COSTS THAT MAY BE NECESSARY FOR NOPS, UPGRADES IDENTIFIED BY THE TRANSMISSION OWNER, IN THIS CASE, THE COMPANY, THAT ARE NECESSARY TO MITIGATE ANY RELIABILITY ISSUES THAT RESULT FROM THE INTERCONNECTION.

A. The Company performed its reliability analysis in 2016 with NOPS included in the base case models representing the electric system. The reliability analysis was performed to assess the Company's ability to comply with NERC Reliability Standard TPL-001-4. The 2016 assessment did not identify any reliability violations associated with a new NOPS for any period within the ten year planning horizon, thus, the Company does not expect additional upgrades to be identified for the foreseeable future.

Q37. DOES THE COMPANY EXPECT THAT ALL NOPS-RELATED PROJECTS IDENTIFIED THROUGHOUT THE TRANSMISSION REVIEW PROCESS WILL BE COMPLETED BY THE CURRENT ESTIMATED NOPS IN-SERVICE DATE?

A. Yes, while the results of the DPP analysis are still unknown, the Company expects that all upgrades required for both the interconnection of the resource and for the NRIS deliverability of the resource will be completed and in-service before the estimated in-service date of NOPS in 2019.

Q38. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF MISSISSIPPI

COUNTY OF Hinds

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES W. LONG**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Charles W. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 9th DAY OF JUNE, 2016

Jon Richard Bewley

NOTARY PUBLIC

MISSISSIPPI STATEWIDE NOTARY PUBLIC
MY COMMISSION EXPIRES MAY 18, 2020
BONDED THRU STEGALL NOTARY SERVICE
MS NOTARY ID # 6095

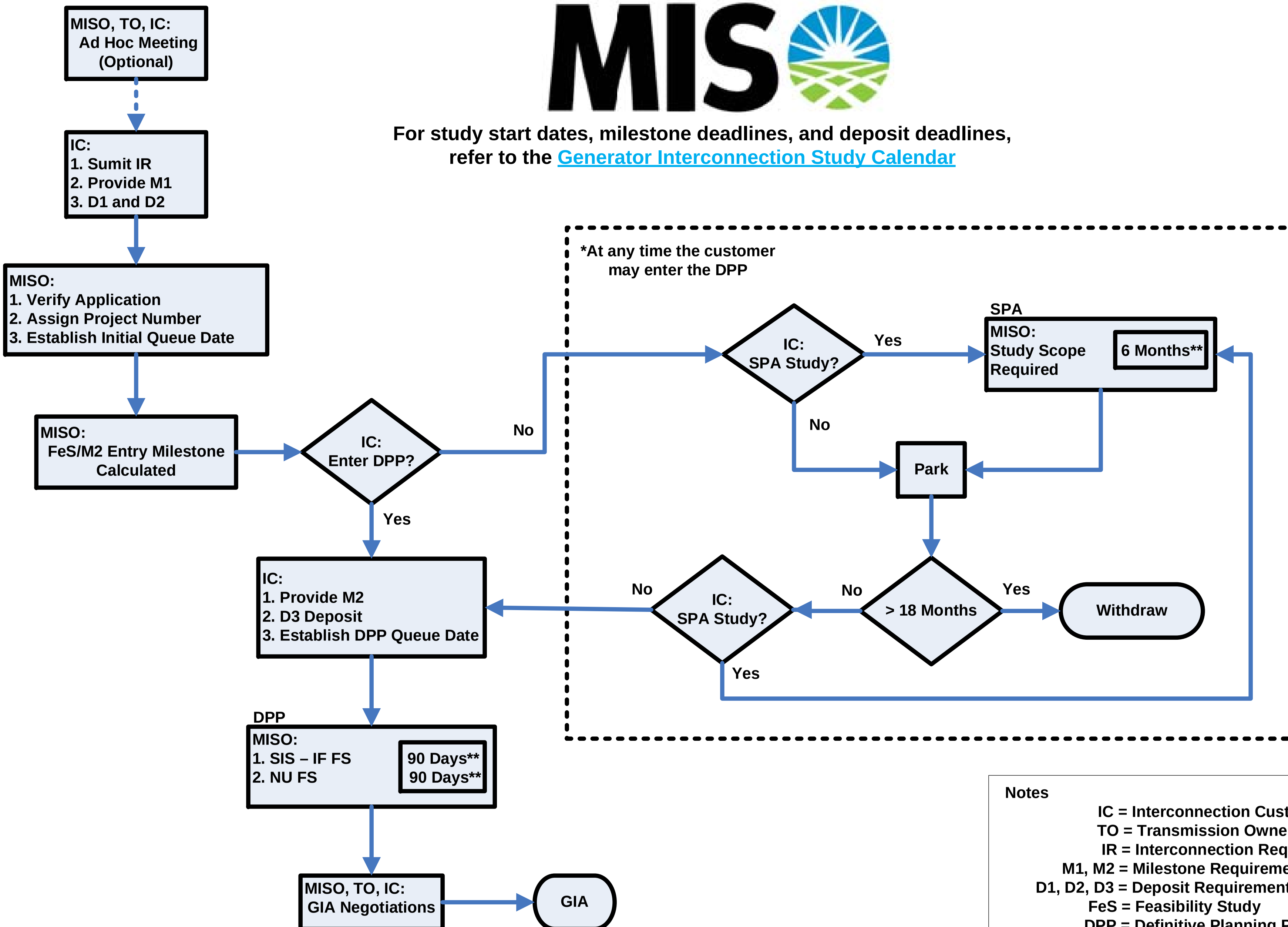
My commission expires: ____________________

STATE OF MISSISSIPPI
NOTARY PUBLIC
ID # 6095
JON RICHARD BEWLEY
Commission Expires
May 18, 2020
HINDS COUNTY

Prior Testimonies of Mr. Charles W. Long

1. DOCKET NO. 43958 – Testimony on behalf of Entergy Texas, Inc. at the Public Utility Service Commission of Texas
2. DOCKET NO. 09-127-U - Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Utility Service Commission
3. DOCKET NO. 10-050-U - Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Utility Service Commission
4. DOCKET NO. 09-110-U - Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Utility Service Commission
5. DOCKET NO. 10-011-U - Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Utility Service Commission
6. DOCKET NO. 09-084-U - Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Utility Service Commission
7. DOCKET NO. U-33770 - Testimony on behalf of Entergy Louisiana, LLC. at the Louisiana Public Service Commission

For study start dates, milestone deadlines, and deposit deadlines, refer to the Generator Interconnection Study Calendar



Notes
IC = Interconnection Customer
TO = Transmission Owner
IR = Interconnection Request
M1, M2 = Milestone Requirements
D1, D2, D3 = Deposit Requirements
FeS = Feasibility Study
DPP = Definitive Planning Phase
SPA = System Planning and Analysis
GIA = Generator Interconnection Agreement
SIS = System Impact Study
NU = Network Upgrade
IF = Interconnection Facilities
FS = Facilities Study
** = Estimated
= Optional

Milestones:

M1:

Non – Technical Requirements

- Complete Application (Appendix 1 with Attachments A, B and C)
- Proof of Site Control or $100,000 deposit in-lieu of site control (dedicated refundable deposit)
    - Project site map indicating lease/ownership interest boundaries
    - Copies of each agreement or copies of the agreements signature pages with a complete sample agreement
    - Document signed by a company executive that states all the listed agreements are on file in their entirety, all referenced land is within the proposed project boundaries, and those agreements constitute 50% or greater ownership of the project's total site.
    - A consultant will review new projects at random and determine if land requirements have been met.

Technical Requirements

- Point of Interconnection (POI)
- Generic Stability Model (for all versions of PSS/e)
    - Wind: A model of the turbines to be used in the project must be provided on a compact disk. If the model is not available, a letter attesting to the type of turbine technology and reactive power capability at the Point of Interconnection must be provided.
    - All Other Generators: Completed Attachment A data/specifications for the project's Generator with non-applicable sections marked accordingly.
- Impedance from collective substation to POI
- Technical data to run studies
- One-line diagram
- Gross and net generation output (MW)
- Step-up Transformer data (POI transmission step up transformer)

System Planning and Analysis (SPA)

Study Requirements

- Provide the SPA Study Scope - Appendix 2 Attachment A

M2:

Non – Technical Requirements

- Definitive Planning Entry Milestone
    - Cash or irrevocable letter of credit
- Proof of Site Control
    - M1 site control deposit becomes non-refundable within 10 days into the DPP cycle and will be applied towards future construction costs
    - M1 site control documentation may be provided and deposit will be refunded

Technical Requirements

- Definitive Point of Interconnection *
- Definitive one line diagram (information including breaker setup, distances to POI on existing lines, and line characteristics) *
- Definitive gross and net generator output (MW) *
- Detailed Stability Model *
    - Wind – PSS/E version 29, 30, 31, or 32
    - Other generator types – All information requested in Attachment A of Appendix 1

*Any material changes (see tariff definition) after this point will result in withdrawal of the project

Note:
For detailed information regarding milestones, please see Attachment X of the MISO Tariff and the Generator Interconnection Business Practices Manual.

Ref	**Description**	**Refund**	**<6 MW**	**≥6 but ≤ 20 MW**	**> 20 but ≤ 50 MW**	**> 50 but ≤ 100 MW**	**> 100 but ≤ 200 MW**	**> 200 but ≤ 500 MW**	**> 500 but < 1000 MW**	**≥ 1000 MW**
D1	Application Fee/Fund FeS	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund System Impact Study (SIS)	Yes	$10,000	$20,000	$30,000	$60,000	$60,000	$60,000	$90,000	$120,000
D3	Fund DPP and Restudies	Partial	$40,000	$100,000	$150,000	$210,000	$260,000	$360,000	$440,000	$520,000

GENERATOR INTERCONNECTION STUDY CALENDAR

- End of 90 day Queue Reform Transition period
- Valid Application Required due date (Note 1)
- Feasibility Study Start date (Note 2)
- M2 milestone payment & D3 Deposit due date (Note 3)
- DPP Study Start date (Note 4)
- SPA Study Scope form due date (Note 5)
- SPA Study Start date (Note 6)

2016 Study Calendar

January

Sun	Mon	Tue	Wed	Thu	Fri	Sat
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2017 Study Calendar

January

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February

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March

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April

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May

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June

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July

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9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

August

Sun	Mon	Tue	Wed	Thu	Fri	Sat
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30	31		

September

Sun	Mon	Tue	Wed	Thu	Fri	Sat
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30

October

Sun	Mon	Tue	Wed	Thu	Fri	Sat
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31				

November

Sun	Mon	Tue	Wed	Thu	Fri	Sat
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30		

December

Sun	Mon	Tue	Wed	Thu	Fri	Sat
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30
31						

Notes:

1. Valid applications must be received by close of business (5:00 p.m. Eastern) 14 calendar days prior to start of Feasibility Study.
   MISO will receive and evaluate applications for completeness prior to the deadline and notify of any deficiencies to be corrected.
   Some dates were adjusted to achieve Monday start dates and to avoid Holiday conflicts.
2. A Feasibility Study will take 10 business days, with results posted within 5 business days. Feasibility Studies will be preformed three times during each DPP cycle.
3. M2 milestone payment and D3 deposit must be received by close of business (5:00 p.m. Eastern) 30 calendar days prior to start of DPP study.
4. DPP two cycles in a calendar year .
5. SPA Study Scope Appendix 2 to GIP Att. A must be received by close of business (5:00 p.m. Eastern) on the posted SPA Study Scope form due date.
6. SPA SIS will start on a periodic basis, with the Interconnection Customer assigned to the next scheduled SIS after receipt of a completed Study Scope.

MISO Project Number	J481	County	Orleans
Point of Interconnection	Michoud 115kV Substation	State	Louisiana
Summer Net Output (MW)	241	Control Area	EES

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

DPP Entry Milestone
$836,523

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

Attachment A

Voltage(kV)	Cost($)
345	350,000
230	200,000
161	130,000
138	130,000
115	130,000
69	125,000

M2 Milestone Payment = 10% x (Total for Number of Feasibility Constraints per Voltage Level x Constant Cost (see chart above) per Voltage Level + Project Size (MW) x Current Schedule 7 MISO Drive-Through Maximum Cost = $10,000 per Gross MW, Minimum Cost = $2,000 per Gross MW

Schedule 7 MISO Drive-Through and Out rate = $34,710.4913

N/A indicates no constraints have been found based on the scope of the feasibility screening.

Attachment Y Study
Michoud Unit 2: 239.4 MW Gas
Retirement
6/1/2016

ATTACHMENT Y STUDY REPORT FINAL

October 16, 2014

Public Version

EXECUTIVE SUMMARY

An Attachment Y Request submitted by the Entergy Services, Inc was received on January 30, 2014. The request was for retirement of Michoud Unit 2 on June 1, 2016.

After being reviewed for Transmission System reliability impacts as provided for under Section 38.2.7 of the MISO Open Access Transmission, Energy & Operating Reserve Markets Tariff ("Tariff"), Michoud Unit 2 may be removed from operation. The Michoud Generating Station unit 2 will not need to be designated as a System Support Resource ("SSR") unit as defined in the EMT.

Contents

I. INTRODUCTION

Entergy Services, Inc submitted an Attachment Y "Notification of Potential Generation Resource/SCU Change of Status" to MISO for the consideration of retiring the Michoud generating station Unit #2 effective from June 1, 2016. The purpose of this study is to assess the reliability impacts from the potential Retirement of the Michoud Unit 2 located in New Orleans, Louisiana. The analysis included the evaluation of various scenarios that considered the offline status of nearby Ninemile Point Unit 3 which was also submitted by Entergy Services Inc concurrently with the Michoud Unit 2 Notice.

Table 1: Units Requesting Retirement/Suspension

Power Flow Area	Unit Description	Total MW	Start Date of Retirement
EES	Michoud Unit 2	239.4	6/1/2016
	Total	239.4	

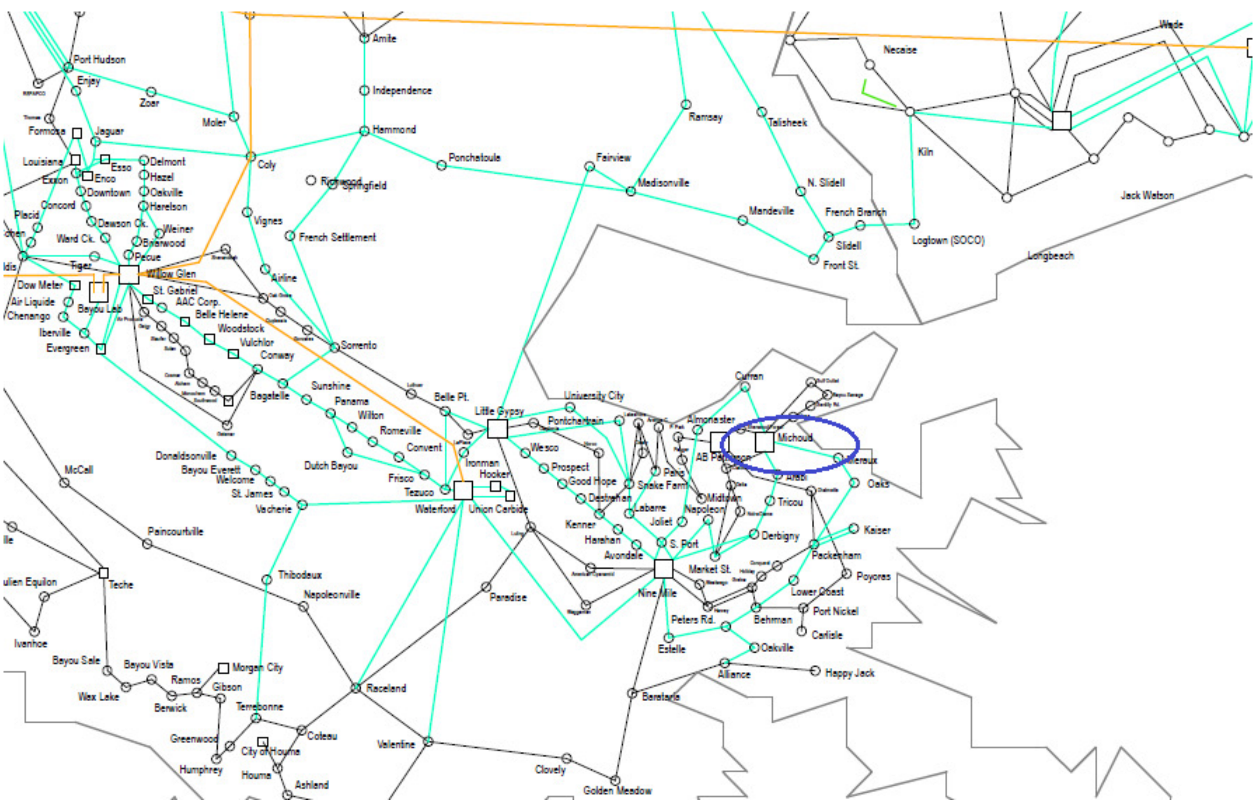


Figure 1: General Location of Michoud Plant in New Orleans, LA

II. STUDY OBJECTIVES

Under Section 38.2.7 the MISO Tariff, System Support Resource (SSR) procedures provide a mechanism for MISO to enter into agreements with Market Participants (MP) that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that have requested to either Retire or Suspend, but are required to maintain system reliability.

The principal objective of an Attachment Y study is to determine if the unit(s) for which a change in status is requested is necessary for system reliability based on the criteria set forth in the MISO Business Practices Manuals. The study work included monitoring and identifying the steady state branch/voltage violations on transmission facilities due to the unavailability of the Generation Resource or SCU. The relevant MISO Transmission Owner and/or regional reliability criteria are used for monitoring such violations.

III. MODELS AND ASSUMPTIONS

Corresponding to the anticipated suspension of the Michoud Station Unit 2, the following power system analysis models were used for the study:

- 2016 Summer Peak
- 2016 Shoulder Peak
- 2019 Summer Peak

The Attachment Y2 study models were created in accordance with the MISO Transmission Planning Business Practice Manual (BPM-020-r10) Section 6.2.2. This includes creating a set of Security Constrained Economic Dispatch (SCED) models from each source model in which the units being studied are taken out of service to represent the "After" retirement scenario. To create the "Before" retirement scenario, generation in MISO was scaled down in each model and then the to-be-retired unit was fully dispatched.

a. Model Assumptions

1. Generation
   - Ninemile 6 is in service as of 3/1/2015
   - Ninemile 3 is not in service effective 6/1/2016
2. Transmission
   None
3. Maintenance Outages
   None
4. Table of Models

n	Source Case	Topology	Michoud 2	Michoud 3	Ninemile 3	Ninemile 6	Contingency Categories
1	MTEP14 2016SP	2016	on	on	on	on	B, C1, C2, C5, Selected C3
2	MTEP14 2016SP	2016	off	on	on	on	B, C1, C2, C5,

Public Version

							Selected C3
3	MTEP14 2019SH	2016	on	on	on	on	B, C1, C2, C5, Selected C3
4	MTEP14 2019SH	2016	off	on	on	on	B, C1, C2, C5, Selected C3
5	MTEP14 2016SP	2016	on	on	off	on	B, C1, C2, C5, Selected C3
6	MTEP14 2016SP	2016	off	on	off	on	B, C1, C2, C5, Selected C3
7	MTEP14 2019SH	2016	on	on	off	on	B, C1, C2, C5, Selected C3
8	MTEP14 2019SH	2016	off	on	off	on	B, C1, C2, C5, Selected C3
9	MTEP14 2019SP	2019	on	on	off	on	B, C1, C2, C5, Selected C3
10	MTEP14 2019SP	2019	off	on	off	on	B, C1, C2, C5, Selected C3

b. Monitoring and Contingencies

Monitor:

- EES(351) Area 69 kV – 999 kV
  - Zone 386 EES_GSU-LA
  - Zone 387 EES_ELL-S
  - Zone 388 EES_ENOI
  - Zone 390 EES_MISS
- CLECO(502) Area 69 kV – 999 kV
  - Zone 503 CLE_EAST
  - Zone 502 CLE_South
- LAGN(332) Area 69 kV – 999 kV

Contingencies:

Category B, C1, C2, C5, selected C3 in 100kV and higher

- EES(351) Area 69 kV – 999 kV
  - Zone 386 EES_GSU-LA
  - Zone 387 EES_ELL-S
  - Zone 388 EES_ENOI
  - Zone 390 EES_MISS
- CLECO(502) Area 69 kV – 999 kV
  - Zone 503 CLE_EAST
  - Zone 502 CLE_South

IV. STUDY CRITERIA AND METHODOLOGY

PSS/E and MUST were used to perform AC contingency analysis. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to find if there were any criteria violations due to the unit(s) change of status.

a. Steady State Thermal and Voltage Criteria

Transmission Owners Planning Criteria

Entergy Transmission Planning Criteria applied for the thermal analysis:

- For Category A contingencies, all thermal loadings exceeding 100% of the normal rating for Entergy System
- For Category B and C contingencies, all thermal loadings exceeding 100% of the normal rating for Entergy System

Entergy Transmission Planning Criteria applied for the voltage analysis:

- For Category A contingencies, all substation voltages less than 95% or above 105%
- For Category B and C contingencies, all substation voltages less than 92% or above 105%

CLECO Transmission Planning Criteria applied for the thermal analysis:

- For Category A contingencies, all thermal loadings exceeding 100% of the emergency rating for CLECO System
- For Category B and C contingencies, all thermal loadings exceeding 100% of the emergency rating for CLECO System

CLECO Transmission Planning Criteria applied for the voltage analysis:

- For Category A contingencies, all substation voltages less than 95% or above 105%
- For Category B and C contingencies, all substation voltages less than 90% or above 105%

LAGN Transmission Planning Criteria applied for the thermal analysis:

- For Category A contingencies, all thermal loadings exceeding 100% of the normal rating for LAGN System
- For Category B and C contingencies, all thermal loadings exceeding 100% of the normal rating for LAGN System

LAGN Transmission Planning Criteria applied for the voltage analysis:

- For Category A contingencies, all substation voltages less than 95% or above 105%
- For Category B and C contingencies, all substation voltages less than 92% or above 105%

Under category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, and/or load shedding will be considered if applicable.

b. MISO Transmission Planning BPM - SSR Criteria

As specified in the MISO BPM-020-r10, the System Support Resource criteria for determining if an identified facility is impacted by the generator change of status will be:

- Under system intact and category B contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" retirement scenario is equal to or greater than:
  - a) 5% of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" retirement scenario, or
  - b) 3% of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" retirement scenario.
- Under system intact and category B contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" retirement voltage calculation.

c. Contingencies

A subset of the MISO Transmission Expansion Plan (MTEP) contingencies in EES and the neighboring control area was used for AC contingency analysis.

The following NERC Categories of contingencies were evaluated:

1. Category A when the system is under normal conditions.
2. Category B contingencies resulting in the loss of a single element.
3. Category C contingencies resulting in the loss of two or more (multiple) elements.

d. Steady State Performance Analysis

Steady State AC contingency analysis was performed using Siemens PSS/E comparing the before and after retirement models.

V. STUDY RESULTS

a. Branch Results (Appendix A Table 1a)

Appendix A shows contingent conditions causing branch criteria violations without Michoud Station Unit 2. Constraints were identified as impacted by the study generators according to SSR criteria.

2016 Summer Peak with Ninemile Point Unit #3 offline

In the analysis of the 2016 Summer Peak with Ninemile Point Unit #3 offline scenario, the retirement of the Michoud Unit 2 results in one NERC Category B violation and several NERC Category C contingency overloads that can be mitigated by generation commitment or redispatch or where load shed is allowed. One constraint is observed for multiple N1G1 contingency events (required per Entergy planning criteria) that cannot be alleviated by available mitigation.

2016 Summer Peak with Ninemile Point Unit #3 dispatched with 103.2MW online

In the analysis of the 2016 Summer Peak with Ninemile Point Unit #3 online scenario, the retirement of the Michoud Unit 2 results in one NERC Category B violation and several NERC Category C contingency overloads that can be mitigated by generation commitment or redispatch or where load shed is allowed. One constraint is observed for multiple N1G1 contingency events (required per Entergy planning criteria) that cannot be alleviated by available mitigation

2016 Summer Shoulder Peak with Ninemile Point Unit #3 offline

In the analysis of the 2016 Summer Shoulder Peak with Ninemile Point Unit #3 offline scenario, the retirement of the Michoud Unit 2 results in several NERC Category C contingency overloads that can be mitigated by generation commitment or redispatch or where load shed is allowed.

2016 Summer Shoulder Peak with Ninemile Point Unit #3 dispatched with 103.2MW online

In the analysis of the 2016 Summer Shoulder Peak with Ninemile Point Unit #3 online scenario, the retirement of the Michoud Unit 2 results in several NERC Category C contingency overloads that can be mitigated by generation commitment or redispatch or where load shed is allowed.

2019 Summer Peak with Ninemile Point Unit #3 offline

In the analysis of the 2019 Summer Peak scenario, the retirement of the Michoud Unit 2 results in one NERC Category B violation and several NERC Category C contingency overloads that can be mitigated by generation commitment or redispatch or where load shed is allowed. One constraint is observed for multiple N1G1 contingency events (required per Entergy planning criteria) that cannot be alleviated by available mitigation.

b. Voltage Results

No constraint is identified as impacted by the study generators according to SSR criteria.

c. Voltage Stability Analysis

The Voltage Stability analysis results show maximum 4351.858 MW DSG load was identified in 2016SP scenario and maximum 4610.306 MW was identified in 2019SP scenarios, no low voltage was identified in the transfer.

A maximum load serving capability of at least 4351 MW are sufficient and would likely be higher in the 2016 Summer case if Little Gypsy 3 unit was turned on.

The details of voltage stability analysis are available in Appendix B.

VI. SSR COST ALLOCATION

Further analysis of the reliability issues was performed to allocate costs for SSR compensation by Local Balancing Authority (LBA) Area. MISO utilizes a load shed methodology to determine the reliability benefits to each MISO Local Balancing Area (LBA) of operation, without the retired or suspended unit(s). Although load shed is not permitted for NERC Category A or B events, this methodology determines the load shed amount needed to resolve the reliability issues identified due to the unit change of status, as a proxy for the reliability benefit of SSR unit operation. The load shed values for each contingency are organized by LBA and accumulated to determine the total load shed for each LBA along with the corresponding share ratio.

Table 2: SSR Agreement LBA/Pricing Zone Shares

Area/PricingZone	Cumulative Load Shed (MW)	Share
EES	605MW	100%

VII. ALTERNATIVES ANALYSIS

a. New Generation or Generation Redispatch

All the generators in DSG load pocket are committed and dispatched to full capacity, no further options exist to provide mitigation by generation redispatch.

b. System Reconfiguration and Operation Guidelines

No system reconfiguration or operating guide alternative is available.

c. Demand Response or Load Curtailment

The study included an optimal load shed analysis to estimate the amount of hypothetical load shed needed to resolve the reliability issues. To fully address all the remaining thermal overloads, the amount of contracted demand response needed was estimated to be 28.45 MW as an alternative to Michoud Unit #2.

d. Transmission Projects

EES has proposed MTEP project 4797 in MTEP 2015 cycle with an in service date of June 2016 This project is to upgrade the jumpers and bus to utilize full rating of Market Street 230/115kV autotransformer. The new rating of Market Street autotransformer after upgrade is 392MVA. This project will completely mitigate the violations identified in this study.

VIII. CONCLUSION

Reliability violations have been identified in the analysis of the retirement of the Michoud Unit 2. These issues will be addressed by Transmission project 4797. Entergy has proposed this project in MTEP 2015 cycle.

After being reviewed for Transmission System reliability impacts as provided for under Section 38.2.7 of the MISO Open Access Transmission, Energy & Operating Reserve Markets Tariff ("Tariff"), Michoud Unit 2 may be removed from operation. The Michoud Generating Station unit 2 will not need to be designated as a System Support Resource ("SSR") unit as defined in the EMT.

IX. APPENDICES

Appendix A: Steady-State AC Contingency Results

Table 1a: Branch Results

Appendix B: Voltage Stability Study

Appendix C: Voltage Stability Study Results

Appendix A

Steady-State AC Contingency Analysis Results

Appendix A, Table 1 - Thermal Analysis Results

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	754.1	534.1	1.101	721.5	517.5	1.05	13.62%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	743.4	526.2	1.085	711.3	509.8	1.03	13.41%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT1	685	723.3	508.1	1.056	691.6	491.7	1	13.24%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	729.1	534.1	1.064	705.6	517.5	1.03	9.82%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	746.6	534.1	1.09	723.2	517.5	1.05	9.77%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	718.2	526.2	1.048	695	509.8	1.01	9.69%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	735.4	526.2	1.074	712.2	509.8	1.03	9.69%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT1	685	714.7	508.1	1.043	691.8	491.7	1	9.57%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT1	685	697.8	508.1	1.019	674.9	491.7	0.98	9.57%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	688.1	534.1	1.005	665.6	517.5	0.97	9.40%	[REDACTED]	MISO: P1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy unit 3 & Waterford 1
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	688.1	534.1	1.005	665.6	517.5	0.97	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy unit 3 & Waterford 1
2016SH_NM3off	336154 6WATFRD 230 - 336190 6GYPSY 230 CKT2	580	646.9	337.3	1.115	620.7	319.4	1.07	10.94%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	336154 6WATFRD 230 - 336190 6GYPSY 230 CKT1	580	647.4	337.8	1.116	621.2	319.8	1.07	10.94%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	707.5	534.1	1.033	685	517.5	1	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	688.1	534.1	1.005	665.6	517.5	0.97	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	691.5	534.1	1.009	669	517.5	0.97	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	687.1	534.1	1.003	664.6	517.5	0.97	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	691.8	534.1	1.01	669.3	517.5	0.97	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	692.1	534.1	1.01	669.6	517.5	0.97	9.40%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	699.4	534.1	1.021	677	517.5	0.98	9.36%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	695	534.1	1.015	672.6	517.5	0.98	9.36%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	693.9	534.1	1.013	671.6	517.5	0.98	9.31%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	696.6	526.2	1.017	674.4	509.8	0.98	9.27%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	688.8	526.2	1.006	666.6	509.8	0.97	9.27%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	336069 6TEZCUCO 230 - 336154 6WATFRD 230 CKT1	641	669.8	392.7	1.045	655.5	393.3	1.02	5.97%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335536 6ADDIS 230 - 335665 6TIGER 230 CKT1	429	431.9	254.7	1.007	424.1	250.1	0.98	3.26%	[REDACTED]	MISO: P7, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335536 6ADDIS 230 - 335665 6TIGER 230 CKT1	429	430.8	254.7	1.004	423.1	250.1	0.98	3.22%	[REDACTED]	MISO: P7, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3off	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1248.5	277	1.045	1208.4	259.3	1.01	16.75%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3

Appendix A, Table 1 - Thermal Analysis Results

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	754.1	534.1	1.101	721.5	517.5	1.05	13.62%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	743.4	526.2	1.085	711.3	509.8	1.03	13.41%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	723.3	508.1	1.056	691.6	491.7	1	13.24%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	721.2	534.1	1.053	697.6	517.5	1.01	9.86%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	779.4	534.1	1.138	755.9	517.5	1.1	9.82%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	797.1	534.1	1.164	773.6	517.5	1.12	9.82%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	710.5	526.2	1.037	687.3	509.8	1	9.69%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	784.6	526.2	1.145	761.5	509.8	1.11	9.65%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	767.3	526.2	1.12	744.2	509.8	1.08	9.65%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	690.4	508.1	1.008	667.4	491.7	0.97	9.61%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	746.2	508.1	1.089	723.3	491.7	1.05	9.57%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	763.2	508.1	1.114	740.3	491.7	1.08	9.57%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335575 6BELL HE 230 - 335576 6WOODSTK 230 CKT 1	685	689.8	436.3	1.007	667	419.9	0.97	9.52%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3off	335576 6WOODSTK 230 - 335579 6VULCHLR 230 CKT 1	685	699.6	447.3	1.021	677.3	431.3	0.98	9.31%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

Scenario	Limiting Element	Rating	Michoud 2 Off Cont. Flow	Michoud 2 Off Base Flow	Michoud 2 Off Loading	Michoud 2 On BF.con. flow	Michoud 2 On BF.Base. Flow	Michoud 2 On Loading	OTDF	Contingency	Comments
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	738.1	526.7	1.078	707.3	511.2	1.03	12.87%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	727.6	518.9	1.062	697.3	503.5	1.01	12.66%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT1	685	707.7	500.7	1.033	677.7	485.5	0.98	12.53%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	718.1	526.7	1.048	696.2	511.2	1.01	9.15%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	735.7	526.7	1.074	713.9	511.2	1.04	9.11%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	724.6	518.9	1.058	703	503.5	1.02	9.02%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	707.4	518.9	1.033	685.8	503.5	1	9.02%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT1	685	704.1	500.7	1.028	682.7	485.5	0.99	8.94%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT1	685	687.1	500.7	1.003	665.7	485.5	0.97	8.94%	[REDACTED]	MISO: P3:N1G1, SSR constraint, OTDF>3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	336154 6WATFRD 230 - 336190 6GYPSY 230 CKT2	580	635.8	329.6	1.096	611.2	312.6	1.05	10.28%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	336154 6WATFRD 230 - 336190 6GYPSY 230 CKT1	580	636.3	330.1	1.097	611.7	313.1	1.05	10.28%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	697.5	526.7	1.018	676.5	511.2	0.98	8.77%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT1	685	689.3	526.7	1.006	668.5	511.2	0.97	8.69%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT1	685	686.7	518.9	1.002	666	503.5	0.97	8.65%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.

Appendix A, Table 1 - Thermal Analysis Results

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SH_NM3on	336069 6TEZCUCO 230 - 336154 6WATFRD 230 CKT1	641	664.1	393.4	1.036	651	394.4	1.01	5.47%	[REDACTED]	MISO: P2, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	335536 6ADDIS 230 - 335665 6TIGER 230 CKT1	429	429.9	254.5	1.002	422.5	250.1	0.98	3.09%	[REDACTED]	MISO: P7, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	335536 6ADDIS 230 - 335665 6TIGER 230 CKT1	429	431	254.5	1.005	423.6	250.1	0.98	3.09%	[REDACTED]	MISO: P7, SSR constraint, OTDF>3%, TO: Non consequential load loss allowed.
2016SH_NM3on	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1229.8	268.1	1.029	1188.6	252.6	0.99	17.21%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	738.1	526.7	1.078	707.3	511.2	1.03	12.87%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	727.6	518.9	1.062	697.3	503.5	1.01	12.66%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	707.7	500.7	1.033	677.7	485.5	0.98	12.53%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	785.9	526.7	1.147	763.6	511.2	1.11	9.31%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	768.1	526.7	1.121	745.9	511.2	1.08	9.27%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	709.9	526.7	1.036	687.9	511.2	1	9.19%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	756.3	518.9	1.104	734.4	503.5	1.07	9.15%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	773.6	518.9	1.129	751.7	503.5	1.09	9.15%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	735.3	500.7	1.073	713.6	485.5	1.04	9.06%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	699.4	518.9	1.021	677.7	503.5	0.98	9.06%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3

Appendix A, Table 1 - Thermal Analysis Results

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SH_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	752.3	500.7	1.098	730.7	485.5	1.06	9.02%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SH_NM3on	335576 6WOODSTK 230 - 335579 6VULCHLR 230 CKT 1	685	688.9	440.1	1.006	667.7	425.3	0.97	8.86%	[REDACTED]	MISO: addi:P3:N1G1, SSR Constraint, OTDF >3%, TO: Insufficient capacity committed in Amite South. Commit Gypsy units 2&3
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	298.6	191.4	1.009	167.2	155.4	0.56	54.89%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	300.5	191.4	1.015	169.2	155.4	0.57	54.85%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	306.7	191.4	1.036	175.6	155.4	0.59	54.76%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	314.4	191.4	1.062	183.4	155.4	0.61	54.72%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.9	191.4	1.033	175	155.4	0.59	54.68%	[REDACTED]	MISO: rerun2:P1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.9	191.4	1.033	175	155.4	0.59	54.68%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	306.2	191.4	1.034	175.3	155.4	0.59	54.68%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.9	191.4	1.033	175	155.4	0.59	54.68%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	307.1	191.4	1.038	176.3	155.4	0.59	54.64%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	306.4	191.4	1.035	175.6	155.4	0.59	54.64%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.9	191.4	1.033	175.1	155.4	0.59	54.64%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	309	191.4	1.044	178.3	155.4	0.6	54.59%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid

Appendix A, Table 1 - Thermal Analysis Results

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.9	191.4	1.05	180.3	155.4	0.6	54.55%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	688	502.7	1.004	665.5	486.9	0.97	9.40%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	705.8	502.7	1.03	683.5	486.9	0.99	9.31%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	695	495.1	1.015	673	479.4	0.98	9.19%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	324.4	191.4	1.096	191.6	155.4	0.64	55.47%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	300.5	191.4	1.015	169.2	155.4	0.57	54.85%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	306.2	191.4	1.034	175.4	155.4	0.59	54.64%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	309.8	191.4	1.047	180.1	155.4	0.6	54.18%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	307.8	191.4	1.04	178.9	155.4	0.6	53.84%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	301.2	191.4	1.018	179.8	155.4	0.6	50.71%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	301.2	191.4	1.018	179.8	155.4	0.6	50.71%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	301.2	191.4	1.018	179.8	155.4	0.6	50.71%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	301.2	191.4	1.018	179.8	155.4	0.6	50.71%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	304.1	191.4	1.027	266.8	155.4	0.9	15.58%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed

Appendix A, Table 1 - Thermal Analysis Results

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SP_NM3off	336080 3CLOVEL 115 - 336081 3GMEADW 115 CKT 1	115	120.3	60.3	1.046	112	56.2	0.97	3.47%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336220 3GYPSY 115 - 336230 3CLAYTN 115 CKT 1	320	428.9	215.9	1.34	421.4	208	1.31	3.13%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336230 3CLAYTN 115 - 336231 3NORCO 115 CKT 1	360	396.4	184	1.101	389	176.1	1.08	3.09%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	306.5	191.4	1.035	175.7	155.4	0.59	52.45%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Valid
2016SP_NM3off	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	307.1	191.4	1.038	176.3	155.4	0.59	52.45%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Valid
2016SP_NM3off	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1318.3	334.5	1.103	1277.9	316.5	1.06	16.20%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1213	334.5	1.015	1187.2	316.5	0.99	10.34%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	727.2	502.7	1.062	704.9	486.9	1.02	8.94%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	744.9	502.7	1.087	722.6	486.9	1.05	8.94%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	733.6	495.1	1.071	711.5	479.4	1.03	8.86%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	716.3	495.1	1.046	694.2	479.4	1.01	8.86%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	695.9	477.1	1.016	674	461.5	0.98	8.78%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3off	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	712.9	477.1	1.041	691	461.5	1	8.78%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	297.5	190.9	1.005	166.2	154.5	0.56	54.85%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303.8	190.9	1.026	172.6	154.5	0.58	54.80%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303	190.9	1.024	172	154.5	0.58	54.72%	[REDACTED]	MISO: rerun2:P1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303.5	190.9	1.025	172.5	154.5	0.58	54.72%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303	190.9	1.024	172	154.5	0.58	54.72%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303.3	190.9	1.025	172.3	154.5	0.58	54.72%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303	190.9	1.024	172	154.5	0.58	54.72%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	304.1	190.9	1.027	173.2	154.5	0.58	54.68%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303	190.9	1.024	172.1	154.5	0.58	54.68%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	306	190.9	1.034	175.3	154.5	0.59	54.59%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	308	190.9	1.041	177.3	154.5	0.59	54.59%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.9	190.9	1.05	180.3	154.5	0.6	54.55%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2016SP_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	695.9	495.9	1.016	678.8	482.6	0.99	7.14%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	685.2	488.3	1	668.3	475.2	0.97	7.06%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	320.9	190.9	1.084	188.1	154.5	0.63	55.47%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	297.5	190.9	1.005	166.2	154.5	0.56	54.85%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303.3	190.9	1.025	172.4	154.5	0.58	54.68%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	307.2	190.9	1.038	177.4	154.5	0.59	54.22%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.3	190.9	1.031	176.2	154.5	0.59	53.93%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	298.4	190.9	1.008	176.9	154.5	0.59	50.75%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	298.4	190.9	1.008	176.9	154.5	0.59	50.75%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	298.4	190.9	1.008	176.9	154.5	0.59	50.75%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	298.4	190.9	1.008	176.9	154.5	0.59	50.75%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	309.4	190.9	1.045	271.8	154.5	0.91	15.71%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	335208 2LK_CH_BLK2! 69 - 335210 4LC BULK 138 CKT 1	100	130.6	114.3	1.306	113.1	114.3	1.13	7.31%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336080 3CLOVEL 115 - 336081 3GMEADW 115 CKT 1	115	117.9	56.7	1.025	109.2	52.5	0.94	3.63%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303.6	190.9	1.026	172.6	154.5	0.58	52.53%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Valid
2016SP_NM3on	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	304.1	190.9	1.027	173.2	154.5	0.58	52.49%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Valid
2016SP_NM3on	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1297.4	325.1	1.086	1271.1	310.6	1.06	10.55%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2016SP_NM3on	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1199.9	325.1	1.004	1182	310.6	0.98	7.18%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	717	495.9	1.047	702.8	482.6	1.02	5.69%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	686	470.4	1.001	671.8	457.3	0.98	5.69%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	706.2	488.3	1.031	692.1	475.2	1.01	5.65%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	734.7	495.9	1.073	720.6	482.6	1.05	5.65%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	723.5	488.3	1.056	709.5	475.2	1.03	5.61%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2016SP_NM3on	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	702.9	470.4	1.026	688.9	457.3	1	5.61%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	303.1	195.3	1.024	171.2	159.2	0.57	55.10%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305	195.3	1.03	173.2	159.2	0.58	55.05%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	319	195.3	1.078	187.4	159.2	0.63	54.97%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	312	195.3	1.054	180.5	159.2	0.6	54.93%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.4	195.3	1.049	179	159.2	0.6	54.89%	[REDACTED]	MISO: rerun2:P1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.4	195.3	1.049	179	159.2	0.6	54.89%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.7	195.3	1.05	179.3	159.2	0.6	54.89%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.4	195.3	1.049	179	159.2	0.6	54.89%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	311.6	195.3	1.053	180.3	159.2	0.6	54.85%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.9	195.3	1.05	179.6	159.2	0.6	54.85%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.4	195.3	1.049	179.1	159.2	0.6	54.85%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	313.5	195.3	1.059	182.3	159.2	0.61	54.80%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	315.4	195.3	1.066	184.3	159.2	0.62	54.76%	[REDACTED]	MISO: rerun2:P3:N1G1, SSR Constraint, OTDF>=3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	328.5	195.3	1.11	195.9	159.2	0.66	55.39%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305	195.3	1.03	173.2	159.2	0.58	55.05%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.7	195.3	1.05	179.4	159.2	0.6	54.85%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	314.5	195.3	1.063	184.3	159.2	0.62	54.39%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	312.8	195.3	1.057	183.4	159.2	0.61	54.05%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.6	195.3	1.032	183.8	159.2	0.62	50.88%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.6	195.3	1.032	183.8	159.2	0.62	50.88%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.6	195.3	1.032	183.8	159.2	0.62	50.88%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

			Michoud 2 Off			Michoud 2 On					
Scenario	Limiting Element	Rating	Cont. Flow	Base Flow	Loading	BF.con. flow	BF.Base. Flow	Loading	OTDF	Contingency	Comments
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	305.6	195.3	1.032	183.8	159.2	0.62	50.88%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	310.9	195.3	1.05	273.4	159.2	0.92	15.66%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	335771 6COLY 2 230 - 335837 8COLY 5 500 CKT 1	1186	1189.1	748.1	1.003	1164.5	730.4	0.98	10.28%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336080 3CLOVEL 115 - 336081 3GMEADW 115 CKT 1	115	122	59.8	1.061	113.7	55.6	0.98	3.47%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336220 3GYPSY 115 - 336230 3CLAYTN 115 CKT 1	320	423.2	220.8	1.323	415.7	212.9	1.29	3.13%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336230 3CLAYTN 115 - 336231 3NORCO 115 CKT 1	360	390.7	189	1.085	383.2	181	1.06	3.13%	[REDACTED]	MISO: rerun2:P2, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	335536 6ADDIS 230 - 335665 6TIGER 230 CKT 1	429	429.2	257.1	1	421.9	252.9	0.98	3.05%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	335536 6ADDIS 230 - 335665 6TIGER 230 CKT 1	429	430.5	257.1	1.003	423.3	252.9	0.98	3.01%	[REDACTED]	MISO: rerun2:P7, SSR Constraint, OTDF>=3%, TO: Non-Consequential load loss allowed
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	311.1	195.3	1.051	179.7	159.2	0.6	52.69%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Valid
2019SP	336420 3MKTST 115 - 336430 6MKTST 230 CKT 1	296	311.6	195.3	1.053	180.3	159.2	0.6	52.65%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Valid
2019SP	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1320.6	319.1	1.105	1280.7	301.4	1.07	16.00%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1209.3	319.1	1.012	1183.5	301.4	0.99	10.34%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335771 6COLY 2 230 - 335837 8COLY 5 500 CKT 1	1186	1189	748.1	1.003	1164.5	730.4	0.98	9.82%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	701.6	482.2	1.024	679.6	466.5	0.99	8.82%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

Scenario	Limiting Element	Rating	Michoud 2 Off Cont. Flow	Michoud 2 Off Base Flow	Michoud 2 Off Loading	Michoud 2 On BF.con. flow	Michoud 2 On BF.Base. Flow	Michoud 2 On Loading	OTDF	Contingency	Comments
2019SP	335569 6POLSCAR 230 - 335573 6A.A.C. 230 CKT 1	685	719.4	482.2	1.05	697.4	466.5	1.01	8.82%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	690.9	474.7	1.009	669.1	459.1	0.97	8.74%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335573 6A.A.C. 230 - 335574 6LICAR 230 CKT 1	685	708.2	474.7	1.034	686.5	459.1	1	8.70%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335574 6LICAR 230 - 335575 6BELL HE 230 CKT 1	685	687.6	456.7	1.004	666.1	441.2	0.97	8.62%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation
2019SP	335825 6FANCY 230 - 335835 8FANCY 500 CKT 1	1195	1220	319.1	1.021	1199.9	301.4	1	8.06%	[REDACTED]	MISO: rerun2_addi:P3:N1G1, SSR Constraint, OTDF>3%, TO: Redispatch solution possible. Increase Amite South generation

MISO Michoud Unit 2 Attachment Y Study - Compare Branch Results

							Michoud 2 Off		Michoud 2 On			
Scenario	Bus Numbe	Bus Name	kV	Area	LV Limit	HV Limit	Cont. Voltage	Base Voltage	BF.con.Vol	BF.base.Vol	Contingency	MISO Comments
None												

Appendix B

Voltage Stability Analysis Results

Appendix B: Voltage Stability Study

Study Objective

The purpose of this voltage stability is to identify voltage constraints limiting transfers in the DSG area and to identify if transfer capability is sufficient to serve DSG load with Ninemile #3 and Michoud #2 retiring. The maximum transfer limits were identified using the DSG load definition described in MISO operating guide [REDACTED].

A P-V study methodology was used for this analysis using the MTEP14 2016 Summer Peak model and the MTEP14 2019 Summer Peak model. Voltages at substations, reactive reserves at significant units and flows on known interfaces were monitored for critical contingencies under various transfer scenarios.

Models and Assumptions

Scenario

n	Source Case	Topology	Michoud 2	Ninemile 3	Ninemile 6	Contingency Categories
1	MTEP14 2016SP	2016	on	on	on	Selected CTG Provided by TO
2	MTEP14 2016SP	2016	off	off	on	Selected CTG Provided by TO
3	MTEP14 2019SP	2019	on	on	on	Selected CTG Provided by TO
4	MTEP14 2019SP	2019	off	off	on	Selected CTG Provided by TO

Contingency

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

Monitor element

- Claiborne 115kV
- Behrman 115kV
- Pauger 115kV
- Estelle 230kV
- Snake Farm 230kV & 115kV
- The reactive power reserves for all units at Little Gyspy, Waterford, and Ninemile

Source (Generation)

- Zone 385 EES_TEXAS
- Zone 386 EES_GSU-LA
- Zone 389 EES_ELL-N
- Zone 390 EES_MISS
- Zone 391 EES_ARK

Sink (Load)

- Zone 387 EES_ELL-S
- Zone 388 EES_ENOI

Study Result

Maximum 4351.858 MW DSG load was identified in 2016SP scenario and maximum 4610.306 MW was identified in 2019SP scenarios, no low voltage was identified in the transfer.

Table below shows the maximum transfer level, the corresponding DSG load and interface flow in the voltage stability study. It is observed that the N1G1 contingency [REDACTED] is the most limiting contingency in all the scenarios. The most limiting maximum transfer amounts are highlighted in red in the table below.

2016SP PV Analysis

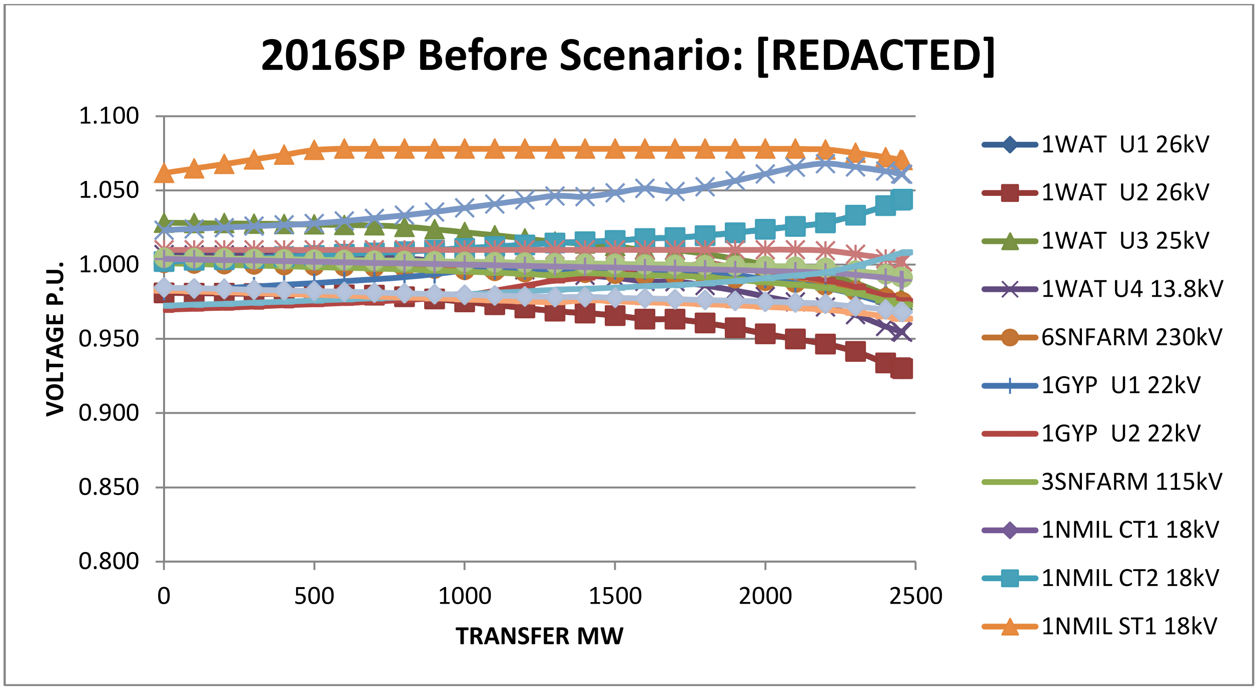
Contingency		Max MW		Max DSG Load		Max DSG interface MW	
		2016SP_before	2016SP_after	2016SP_Before	2016SP_After	2016SP_Before	2016SP_After
#	BASE CASE	3675	3200	5271.083	5020.78	2407.284	2497.921
1	[REDACTED]	3506.25	3050	5187.631	4947.53	2323.668	2424.457
2	[REDACTED]	3393.75	3193.75	5119.408	5017.696	2255.217	2494.81
3	[REDACTED]	3587.5	3056.25	5231.617	4949.494	2367.773	2426.413
4	[REDACTED]	3500	3150	5180.826	4999.643	2316.761	2476.65
5	[REDACTED]	2612.5	2206.25	4616.942	4492.958	1745.95	1967.35
6	[REDACTED]	2725	2087.5	4738.03	4431.497	2588.365	2624.489
7	[REDACTED]	2950	2268.75	4839.738	4527.527	2540.923	2571.844
8	[REDACTED]	2512.5	1918.75	4633.805	**4351.858**	2484.02	2544.882

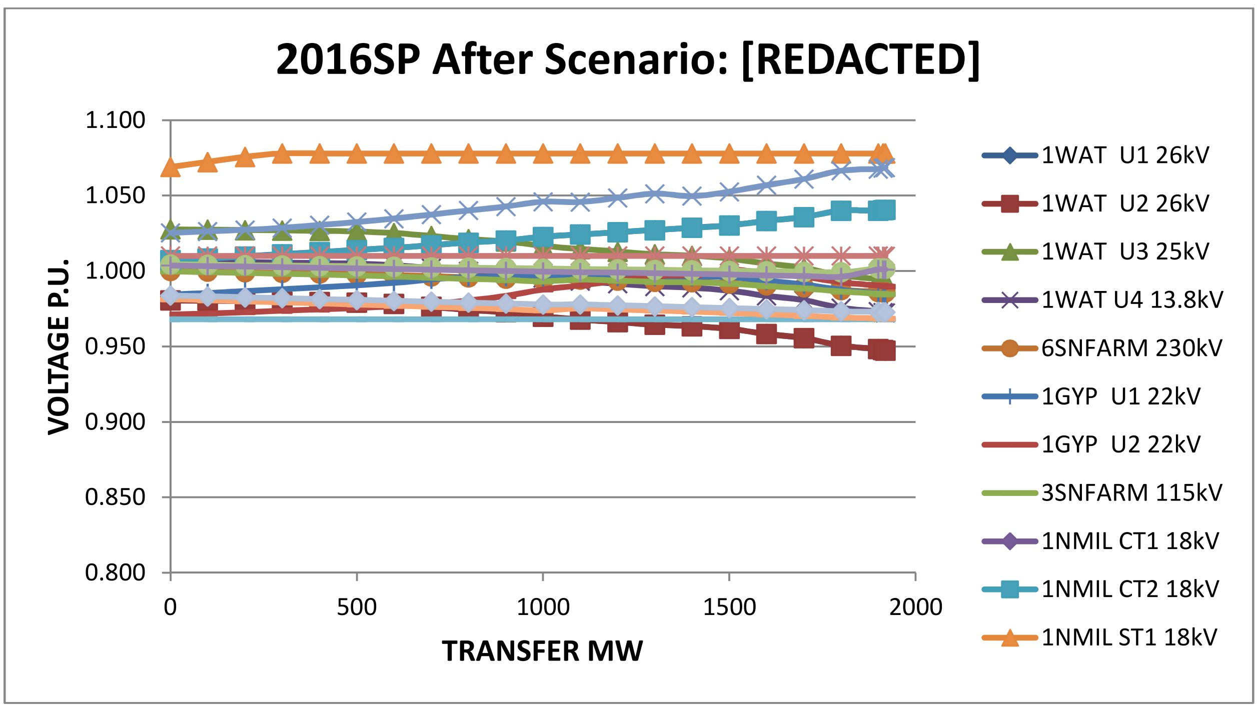
2019 PV Analysis

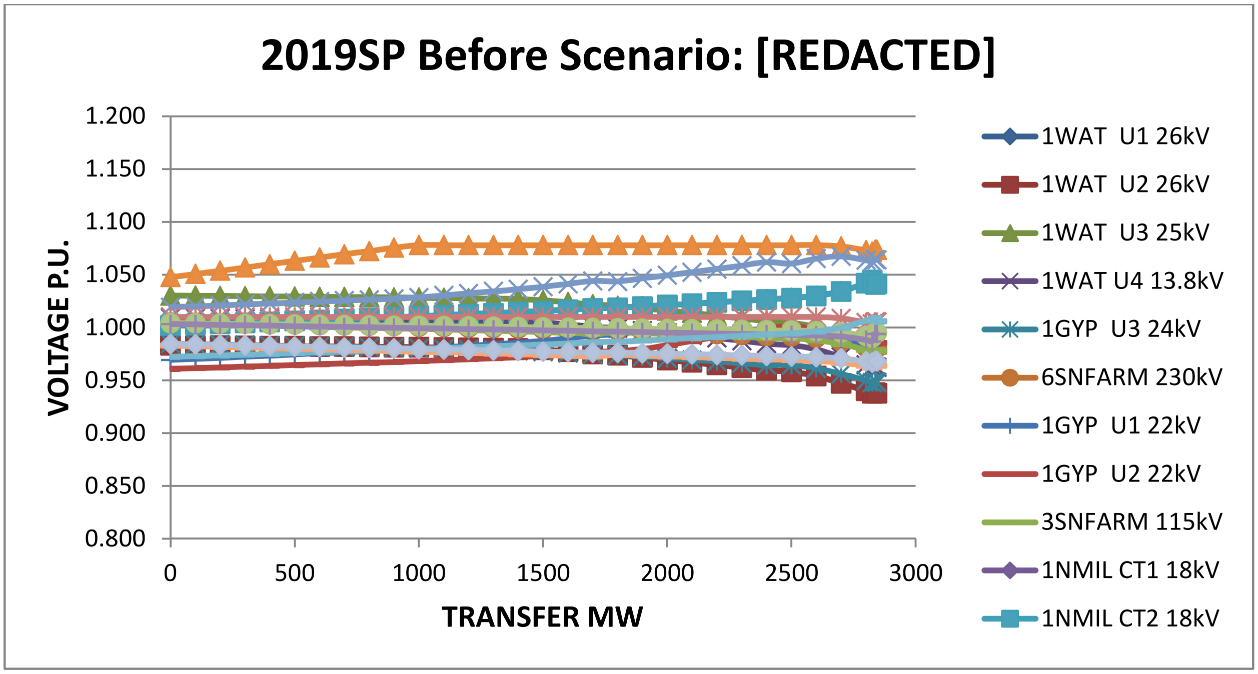
Contingency		Max MW		Max DSG Load		Max DSG interface MW	
		2019SP_before	2019SP_after	2019SP_Before	2019SP_After	2019SP_Before	2019SP_After
#	BASE CASE	4050	3568.75	5522.458	5268.992	2658.933	2746.322
1	[REDACTED]	3887.5	3412.5	5443.678	5194.499	2580.02	2671.757
2	[REDACTED]	4043.75	3560.15625	5519.683	5264.009	2656.161	2741.264
3	[REDACTED]	3943.75	3450	5473.729	5212.983	2610.119	2690.211
4	[REDACTED]	3887.5	3493.75	5439.816	5235.426	2576.023	2712.677
5	[REDACTED]	3575	2987.5	5198.828	4932.656	2331.96	2406.449
6	[REDACTED]	3056.25	2643.75	4854.692	4764.908	1983.549	2239.416
7	[REDACTED]	3075	2506.25	4966.766	4698.357	2816.994	2891.984
8	[REDACTED]	3300	2706.25	5075.185	4777.369	2776.385	2819.193
9	[REDACTED]	2918.75	2325	4894.382	**4610.306**	2744.536	2803.932

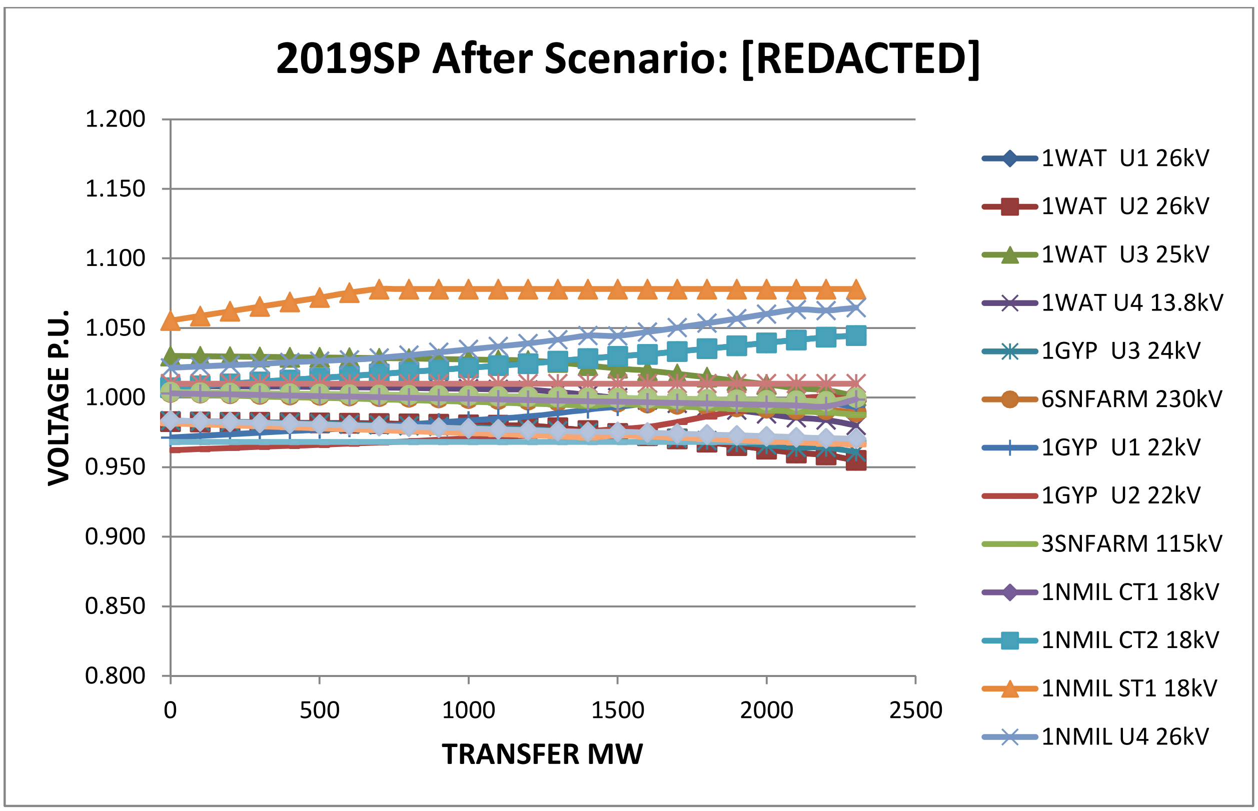
The PV plots of voltages at the monitoring substation are available in Appendix C. the generation reserve table can also be found in Appendix C.

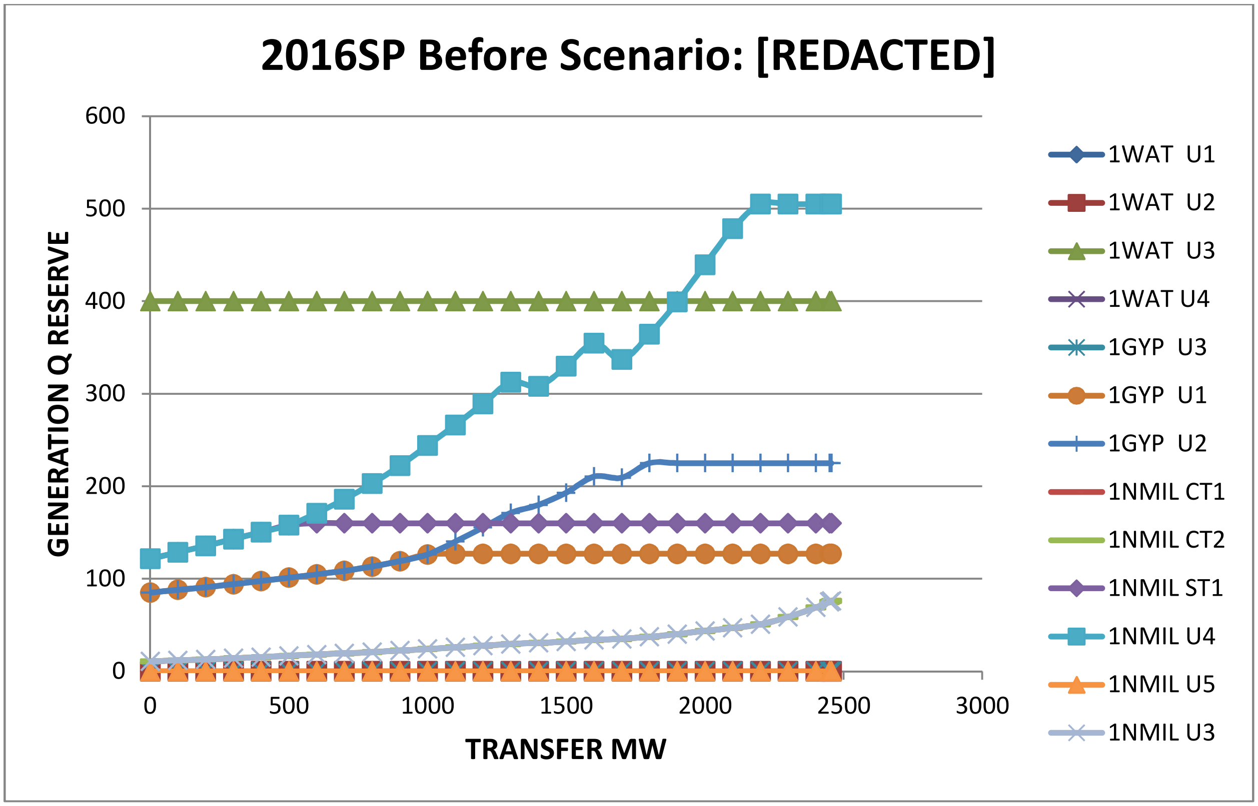
Below are the chart shows voltage changes in the transfer and how generation reactive power reserves gradually deplete in the transfer under contingency 9M_WD230+9M5, which is the most limiting contingency in all scenarios.

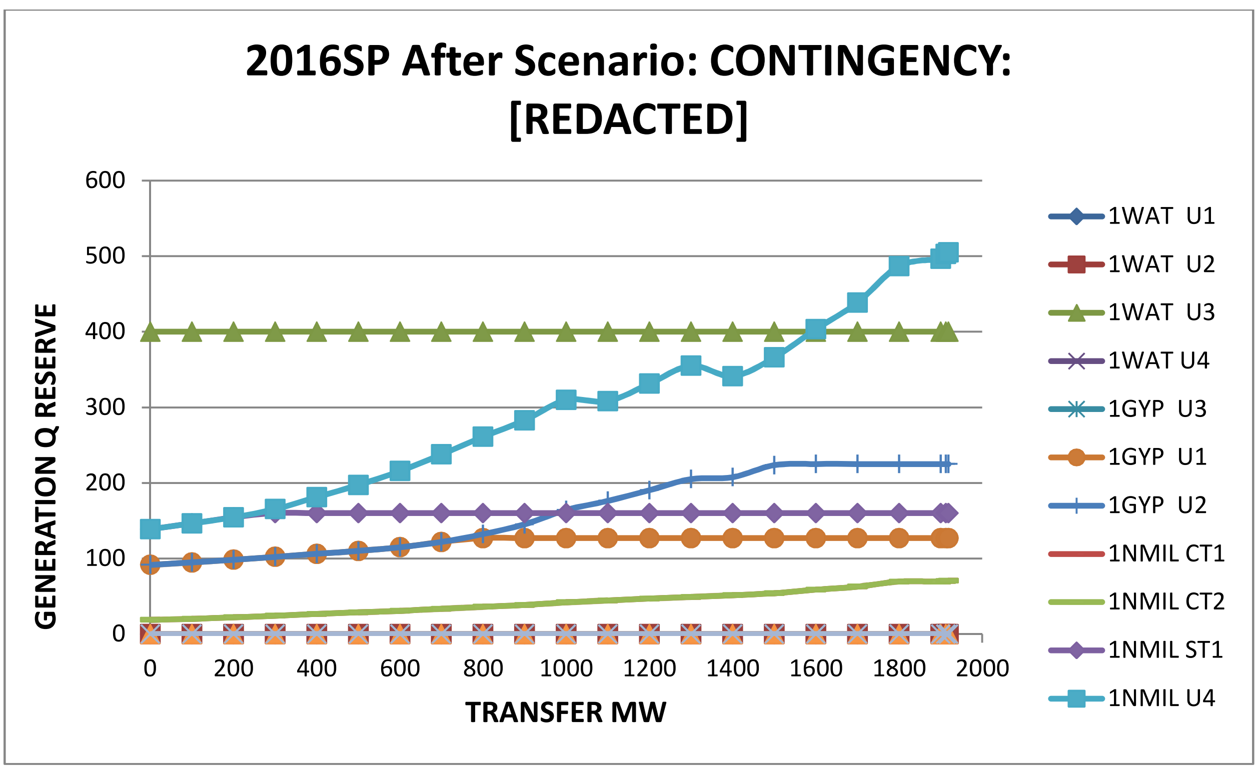

2016SP Before Scenario: [REDACTED]
1.100
1.050
1.000
0.950
0.900
0.850
0.800
VOLTAGE P.U.
0
500
1000
1500
2000
2500
TRANSFER MW
1WAT U1 26kV
1WAT U2 26kV
1WAT U3 25kV
1WAT U4 13.8kV
6SNFARM 230kV
1GYP U1 22kV
1GYP U2 22kV
3SNFARM 115kV
1NMIL CT1 18kV
1NMIL CT2 18kV
1NMIL ST1 18kV

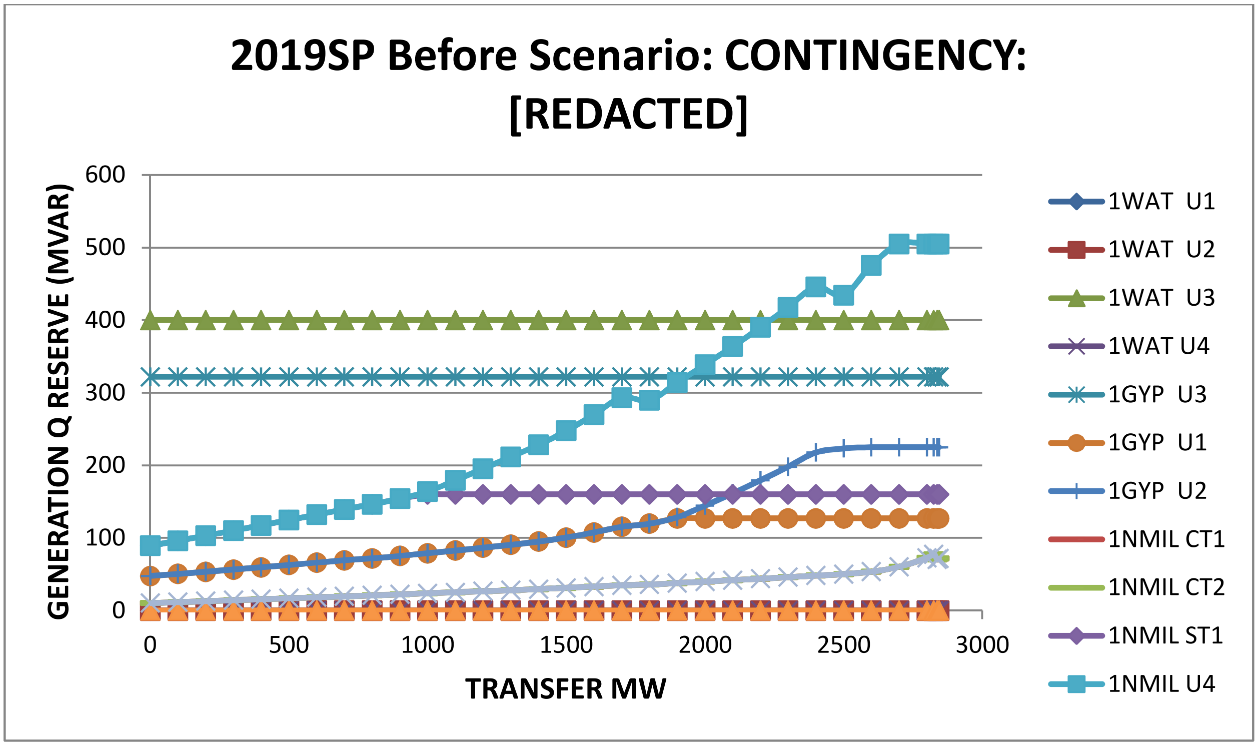

2016SP After Scenario: [REDACTED]
1.100
1.050
1.000
0.950
0.900
0.850
0.800
VOLTAGE P.U.
0
500
1000
1500
2000
TRANSFER MW
1WAT U1 26kV
1WAT U2 26kV
1WAT U3 25kV
1WAT U4 13.8kV
6SNFARM 230kV
1GYP U1 22kV
1GYP U2 22kV
3SNFARM 115kV
1NMIL CT1 18kV
1NMIL CT2 18kV
1NMIL ST1 18kV

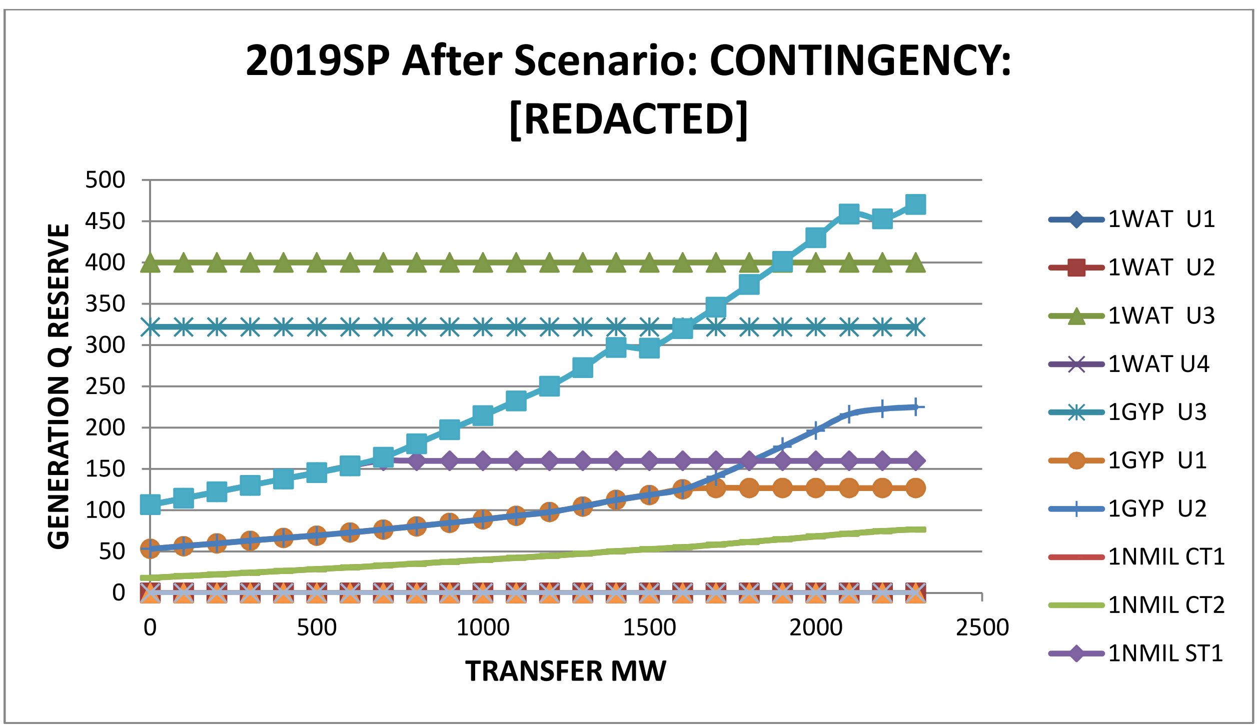

2019SP Before Scenario: [REDACTED]
VOLTAGE P.U.
1.200
1.150
1.100
1.050
1.000
0.950
0.900
0.850
0.800
0
500
1000
1500
2000
2500
3000
TRANSFER MW
1WAT U1 26kV
1WAT U2 26kV
1WAT U3 25kV
1WAT U4 13.8kV
1GYP U3 24kV
6SNFARM 230kV
1GYP U1 22kV
1GYP U2 22kV
3SNFARM 115kV
1NMIL CT1 18kV
1NMIL CT2 18kV


2019SP After Scenario: [REDACTED]
VOLTAGE P.U.
1.200
1.150
1.100
1.050
1.000
0.950
0.900
0.850
0.800
0
500
1000
1500
2000
2500
TRANSFER MW
1WAT U1 26kV
1WAT U2 26kV
1WAT U3 25kV
1WAT U4 13.8kV
1GYP U3 24kV
6SNFARM 230kV
1GYP U1 22kV
1GYP U2 22kV
3SNFARM 115kV
1NMIL CT1 18kV
1NMIL CT2 18kV
1NMIL ST1 18kV
1NMIL U4 26kV


2016SP Before Scenario: [REDACTED]
GENERATION Q RESERVE
TRANSFER MW
0
100
200
300
400
500
600
0
500
1000
1500
2000
2500
3000
1WAT U1
1WAT U2
1WAT U3
1WAT U4
1GYP U3
1GYP U1
1GYP U2
1NMIL CT1
1NMIL CT2
1NMIL ST1
1NMIL U4
1NMIL U5
1NMIL U3


2016SP After Scenario: CONTINGENCY: [REDACTED]
GENERATION Q RESERVE
TRANSFER MW
0
100
200
300
400
500
600
0
200
400
600
800
1000
1200
1400
1600
1800
2000
1WAT U1
1WAT U2
1WAT U3
1WAT U4
1GYP U3
1GYP U1
1GYP U2
1NMIL CT1
1NMIL CT2
1NMIL ST1
1NMIL U4


2019SP Before Scenario: CONTINGENCY:
[REDACTED]
GENERATION Q RESERVE (MVAR)
600
500
400
300
200
100
0
0
500
1000
1500
2000
2500
3000
TRANSFER MW
1WAT U1
1WAT U2
1WAT U3
1WAT U4
1GYP U3
1GYP U1
1GYP U2
1NMIL CT1
1NMIL CT2
1NMIL ST1
1NMIL U4


2019SP After Scenario: CONTINGENCY:
[REDACTED]
GENERATION Q RESERVE
500
450
400
350
300
250
200
150
100
50
0
0
500
1000
1500
2000
2500
TRANSFER MW
1WAT U1
1WAT U2
1WAT U3
1WAT U4
1GYP U3
1GYP U1
1GYP U2
1NMIL CT1
1NMIL CT2
1NMIL ST1

Conclusions

This analysis is not intended to establish actual operating boundaries for the study regions. However, the results of this study may be used to compare with real time assessment studies and provide reference to real time operation to monitor the change in these transfer limits.

This study did not find low voltage issue for critical contingencies, Maximum 4351.858 MW DSG load was identified in 2016SP scenario and maximum 4610.306 MW was identified in 2019SP scenarios, no low voltage was identified in the transfer.

Appendix C

Voltage Stability Study PV plot and data table

[REDACTED]

ENTERGY NEW ORLEANS, INC.
MICHOUD 3: 542.4 MW (Gas)
Retirement - 6/01/2016

ATTACHMENT Y STUDY REPORT

FINAL

July 28, 2015

Public Version

EXECUTIVE SUMMARY

An Attachment Y notification submitted by the Entergy New Orleans, Inc. was received by MISO on December 19th 2014. The request was for Retirement of Michoud Unit 3 starting June 1st 2016. MISO performed a transmission system reliability assessment that was reviewed and discussed with the impacted Transmission Owners (TOs): Entergy and Cleco. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of the MISO's Open Access Transmission, Energy & Operating Reserve Markets Tariff ("Tariff"), Michoud Unit 3 will be required as a System Support Resource(s) until transmission upgrades are completed to eliminate the reliability violations caused by the unit Retirement.

The Attachment Y study indicates that reliability issues exist as a result of the retirement of the Michoud Unit 3. Therefore retirement of Michoud Unit 3 prior to implementing required mitigations will result in violation of the applicable reliability criteria and potential disruption of power supply to the loads in the area under contingencies.

Entergy has proposed three transmission projects to address reliability issues (thermal and voltage violations) identified in the Attachment Y Study - i) upgrade of existing Nine Mile to Napoleon 230 KV line, ii) upgrade of existing Nine Mile to Derbigny 230 KV line and iii) reconfiguration of 115 kV yard at Franklin substation to a double-bus-double-breaker scheme. Entergy has indicated that it will accelerate these projects to complete the work before the retirement of Michoud Unit 3 (June 1, 2016).

Contents

I. INTRODUCTION

The Market Participant Entergy New Orleans, Inc. submitted an Attachment Y Notice to MISO dated 12/19/2014 for the Retirement of the Michoud Unit 3 effective 06/01/2016. Michoud Unit 3 is gas generator with a capacity of 542.4 MW and is connected to the 230kV Entergy Transmission System. The plant is located in New Orleans, Louisiana.

Table 1: Units Requesting Retirement

Power Flow Area	Unit Description	Total MW	Start Date of Retirement
EES	Michoud 3	542.4	06/01/2016

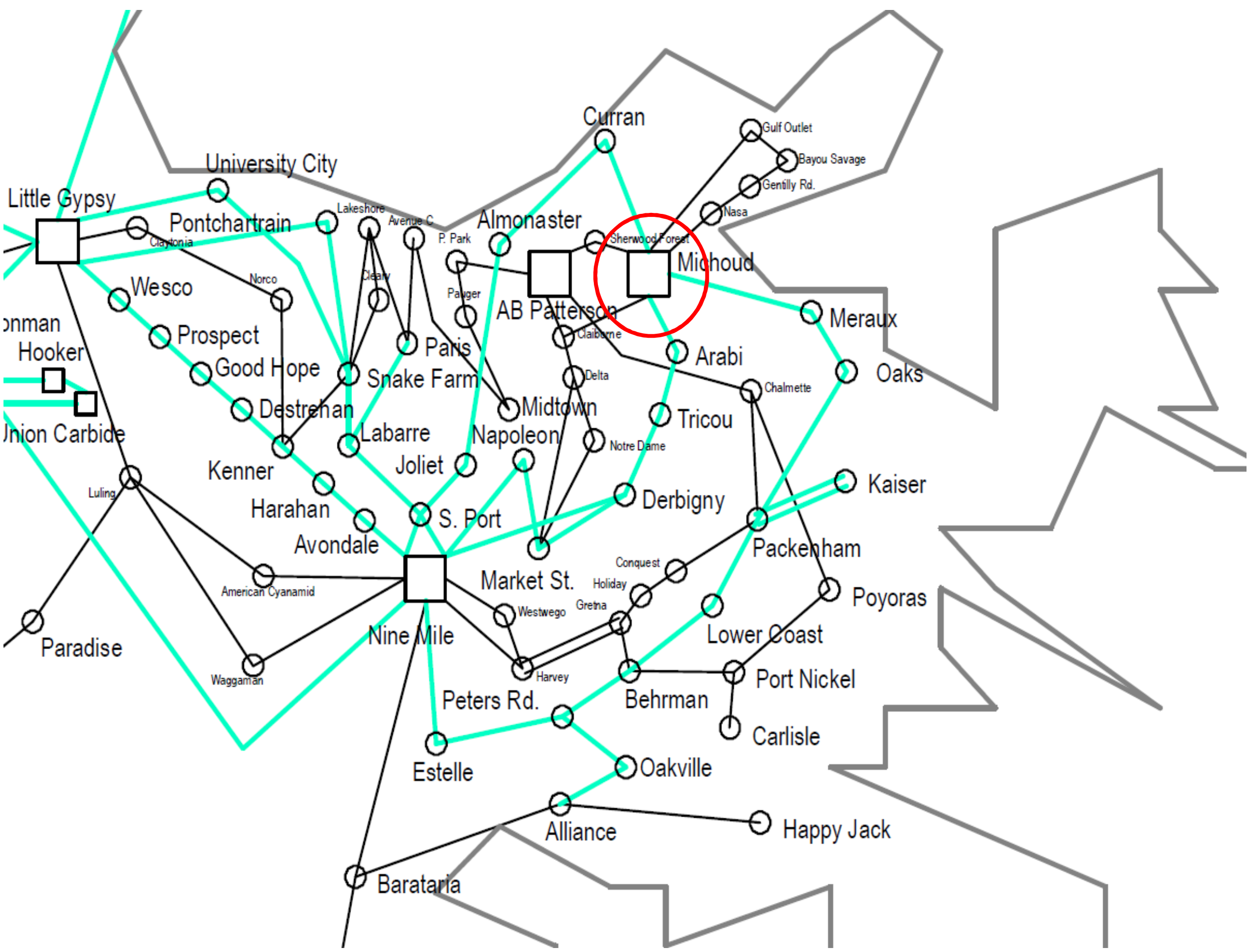


Figure 1.0: Location of Michoud 3 in New Orleans, Louisiana

II. STUDY OBJECTIVES

Under Section 38.2.7 the MISO Tariff, System Support Resource (SSR) procedures provide a mechanism for MISO to enter into agreements with Market Participants (MP) that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that have requested to either Retire or Suspend, but are required to maintain system reliability.

The principal objective of an Attachment Y study is to determine if the unit(s) for which a change in status is requested is necessary for system reliability based on the criteria set forth in the MISO Business Practices Manuals. The study work included monitoring and identifying the steady state thermal/voltage violations on transmission facilities due to the unavailability of the Generation Resource or SCU. The relevant MISO Transmission Owner and/or regional reliability criteria are used for monitoring such violations.

III. MODELS AND ASSUMPTIONS

Corresponding to the anticipated retirement of the Michoud unit 3, the following power system analysis models were used for the study:

- MTEP14 – 2016 Summer Model
- MTEP14 – 2016 Shoulder Model
- MTEP14 – 2019 Summer Model

The Attachment Y study models were created in accordance with the MISO Transmission Planning Business Practice Manual (BPM-020-r11) Section 6.2.2. This includes creating a set of Security Constrained Economic Dispatch (SCED) models from each source model in which the units being studied are taken out of service to represent the "After" retirement scenario. To create the "Before" retirement scenario, generation in MISO was scaled down in each model and then the to-be-retired unit was fully dispatched.

a. Model Assumptions

1. Generation
   a. Ninemile Point Unit 6 is in service as of 3/1/2015
   b. Michoud Unit 2 is not in service effective 6/1/2016 – Approved retirement
   c. Ninemile Point Unit 3 is not in service effective 6/1/2016 – Approved Retirement

2. Transmission
   All the Approved Appendix A projects from MTEP14 are included in the study case. Additionally, following transmission projects are included into the study models
   a. Upgrade Market St Bus and Jumpers – completed 5/27/2015
   b. Richardson - Iberville, New Richardson substation and line to Iberville – 12/01/2018
   c. Romeville Upgrade line bay bus – 12/01/2017
   d. Panama: Bagatelle-Sorrento cut in, Bagatelle - Sorrento cut-in - 12/01/2018

3. Load
    a. 2016 Summer and Shoulder – A load growth of 495 MW is included of which 45 MW is in DSG load pocket and 128 MW is in Amite South load pocket.
    b. 2019 Summer – A load growth of 1688 MW is included of which 45 MW is in DSG load pocket and 214 MW is in Amite South load pocket.

b. Operating Guides

The following operating guides are considered:
- [REDACTED]
- {REDACTED]

c. Table of Models

Table 2: Table of Models

Sno	Source Case	Michoud 3	Ninemile 3	Michoud 2	Ninemile 6	Willow Glen 2&4
1	MTEP14 2016SP	ON	OFF	OFF	ON	ON
2	MTEP14 2016SP	OFF	OFF	OFF	ON	ON
3	MTEP14 2016SH	ON	OFF	OFF	ON	ON
4	MTEP14 2016SH	OFF	OFF	OFF	ON	ON
5	MTEP14 2019SP	ON	OFF	OFF	ON	ON
6	MTEP14 2019SP	OFF	OFF	OFF	ON	ON
7	MTEP14 2019SH	ON	OFF	OFF	ON	ON
8	MTEP14 2019SH	OFF	OFF	OFF	ON	ON

d. Maintenance Outages

None

e. Monitor

- EES(351) Area 69 kV – 999 kV
    - Zone 386 EES_GSU-LA
    - Zone 387 EES_ELL-S
    - Zone 388 EES_ENOI
    - Zone 390 EES_MISS
- CLECO(502) Area 69 kV – 999 kV
    - Zone 503 CLE_EAST
    - Zone 502 CLE_South
- LAGN(332) Area 69 kV – 999 kV

f. Contingencies

NERC Category P1, P2, and P3 contingencies of 100kV and higher for the following areas:

- EES(351) Area 69 kV – 999 kV
  - Zone 386 EES_GSU-LA
  - Zone 387 EES_ELL-S
  - Zone 388 EES_ENOI
  - Zone 390 EES_MISS
- CLECO(502) Area 69 kV – 999 kV – contact CLECO
  - Zone 503 CLE_EAST
  - Zone 502 CLE_South

IV. CONTINGENCIES STUDY CRITERIA & METHODOLOGY

PSS/E and TARA were used to perform AC contingency analysis and SCED. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to find if there are any criteria violations due to the change of status of Michoud Unit 3.

a. Contingencies

A subset of the MISO Transmission Expansion Plan (MTEP) contingencies in EES and the neighboring control areas were used for AC contingency analysis.

The following NERC Categories of contingencies were evaluated:

1. NERC Category A(P0) when the system is under normal conditions.
2. NERC Category B (P1) contingencies resulting in the loss of a single element.
3. NERC Category C (P2 – P3) contingencies resulting in the loss of two or more (multiple) elements.

NERC Category P4 and above contingencies were not provided by Transmission Owners for this study.

b. Steady State Thermal and Voltage Criteria

1. Entergy Transmission Owners Planning Criteria (Effective 09/01/2014)

   Entergy Transmission Planning Criteria applied for the thermal analysis:
   - For NERC Category P0 contingencies, all thermal loadings exceeding 100% of the normal rating for Entergy System
   - For NERC Category P1 - P6 contingencies, all thermal loadings exceeding 100% of the normal rating for Entergy System

   Entergy Transmission Planning Criteria applied for the voltage analysis:

- For NERC Category P0 contingencies
    - KV>=300 - all substation voltages less than 97.5% or above 105%
    - 100 < KV< 300 – all substation voltages less than 95% or above 105%
- For NERC Category P1- P6 contingencies
    - KV >300 – all substation voltages less than 95% or above 105%
    - 100 < KV< 300 - all substation voltages less than 92% or above 105% for load or gen bus
    - 100 < KV< 300 - all substation voltages less than 90% or above 105% for non load or non gen bus
    - all substation voltages less than 90% or above 105% for non BES facilities

2. LAGN Transmission Owners Planning Criteria – Entergy planning criteria are applicable to LAGN facilities.

3. CLECO Transmission Owners Planning Criteria (Effective 03/20/2013)

   CLECO Transmission Planning Criteria applied for the thermal analysis:

   - For NERC Category A (P0) contingencies, all thermal loadings exceeding 100% of the emergency rating for CLECO System
   - For NERC Category B(P1) and C (P2-P6) contingencies, all thermal loadings exceeding 100% of the emergency rating for CLECO System

   CLECO Transmission Planning Criteria applied for the voltage analysis:

   - For NERC Category A(P0) contingencies, all substation voltages less than 95% or above 105%
   - For NERC Category B(P1) and C(P2-P6) contingencies, all substation voltages less than 90% or above 105%

   Under NERC Category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, and/or load shedding will be considered if applicable.

4. MISO Transmission Planning BPM - SSR Criteria

   As specified in the MISO BPM-020-r11, the System Support Resource criteria for determining if an identified facility is impacted by the generator change of status is the following:

   - Under system intact and contingency events, branch thermal violations are only valid if the flow increase on the element in the “after” retirement scenario is equal to or greater than:
       - 5% of the “to-be-retired” unit(s) MW amount (i.e. 5% PTDF) for a “base” violation compared with the “before” retirement scenario, or

- 3% of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" retirement scenario.

- Under system intact and contingency events, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" retirement voltage calculation.

V. STUDY RESULTS

Appendix A to this report includes all constrained elements found to be affected by the retirement of Michoud Unit 3.

a. 2016 Summer Peak Analysis

Several thermal violations (loading percentage greater than 100% and OTDF on the line greater than 3%) were observed with Michoud 3 offline and are included in the Appendix A. One facility with thermal overloads resulting from two NERC Category P3 (G1N1) events can be mitigated with generation redispatch. Three facilities with thermal overloads resulting from one NERC Category P2 event can be mitigated by load shed (allowed as per NERC TPL standards). Four facility overloads resulting from one NERC Category P2 event can be avoided by use of a temporary operating procedure to reconfigure the station bus.

Thermal overloads on the following two facilities resulting from four NERC Category P2 events could not be relieved:

- Nine Mile to Napoleon 230 KV line with loading percentage greater than 100% in the OFF case and OTDF of 23% when compared with ON case.
- Nine Mile to Derbigny 230 KV line with loading percentage greater than 100% in the OFF case and OTDF of 25% when compared with ON case.

Several 115kV voltage violations were observed in the 2016 Summer Peak analysis for NERC Category P2 events which could not be relieved.

b. 2016 Shoulder Analysis

The 2016 Shoulder analysis also resulted in several thermal violations with Michoud 3 offline and are included in the Appendix A. One facility with thermal overload resulting from one NERC Category P3 (G1N1) events can be mitigated with generation redispatch. Two facilities with thermal overloads resulting from two NERC Category P2 events can be mitigated by load shed (allowed as per NERC TPL standards). Two facility overload resulting from one NERC Category P2 event can be avoided by use of a temporary operating procedure to reconfigure the station bus.

No voltage violations were observed in the 2016 Shoulder Analysis.

c. 2016 Shoulder Analysis with Waterford Unit 3 Outage

Analysis of the 2016 Shoulder model was performed with the additional outage of the Waterford nuclear Unit 3 to assess the operational impacts beyond the planning criteria. With the Michoud Unit 3 retirement, the recurring outages for nuclear refueling and maintance of Waterford Unit 3 further reduces the available generation needed to support the Amite South load pocket. The analysis suggested a need of system reconfiguration plan(s) and generation commitment to avoid the potential risk of load shed of up to 192MW during the planned outage. The analysis revealed two facilities with thermal overloads as a result of NERC Category P3 (G1N1) events that can be mitigated with appropriate generation redispatch to support the outage plan. Two facility overloads resulting from NERC Category P2 events can be avoided by use of a temporary operating procedure to reconfigure the station bus during the outage. Five facility overloads resulting from NERC Category P2 events can be addressed by commitment and dispatch of additional generation to support the outage plan. All voltage issues observed in the analysis resulting from the five NERC Category P2 contingencies are mitigated by turning on switched capacitors. The results of this analysis were discussed further with Entergy Transmission Planning and Operations personnel for potential concerns of operational risks, and Entergy agreed that risks would be adequately managed without the need for additional operating procedures. Results of the Waterford Unit 3 outage assessment are included in Appendix B.

d. 2019 Summer Peak Analysis

Similar to 2016 Summer peak analysis several thermal violations (loading percentage on the line greater than 100% and OTDF greater than 3%) were observed with Michoud unit 3 offline and are included in the Appendix A. One thermal overload caused by a NERC Categogy P3 event can be addressed by generation redispatch. One facility with thermal overload resulting from one NERC Category P2 event can be mitigated by load shed (allowed as per NERC TPL standards). Four facility overloads resulting from one NERC Category P2 event can be avoided by use of a temporary operating procedure to reconfigure the station bus.

Thermal overloads on the following two facilities resulting from five NERC Category P2 events and one NERC Category P1 event could not be relieved:

- Nine Mile to Napoleon 230 KV line with loading percentage greater than 100% in the OFF case and OTDF of 24% when compared with ON case.
- Nine Mile to Derbigny 230 KV line with loading percentage greater than 100% in the OFF case and OTDF of 69% when compared with ON case.

No voltage violations were observed in the 2019 Summer Peak analysis.

VI. SSR AGREEMENT COST ALLOCATION

MISO utilizes an optimal load shed methodology to determine the reliability benefits to each MISO Local Balancing Area (LBA) from the operation of the SSR unit(s). The LBA shares that are calculated in this analysis are used for cost allocation if an SSR agreement is necessary. Although load shed is not permitted for NERC Category P0, P1 and P2 (EHV) events, this methodology determines the load shed amount needed to resolve all reliability issues identified due to the unit change of status, as a proxy for the reliability benefit of the SSR unit operation. The hypothetical SSR agreement shares that were calculated for this Attachment Y study are included below in Table 3.

Table 3: SSR Agreement LBA Shares

LBA	Load Shed (MW)	Share
EES	184	100%

VII. ALTERNATIVES ANALYSIS

a. New Generation or Generation Redispatch

All the generators in DSG and Amite South load pockets are committed and dispatched to full capacity in Summer Peak cases. In 2016 Shoulder case one G1N1 contingency caused thermal violation on the 230 KV line from St Gabriel to AAC Corp which can be mitigated by increasing the generation at Little Gypsy Unit 2. This constraint and the relevant comments are captured in the Appendix A.

b. System Reconfiguration and Operation Guidelines

None identified.

c. Demand Response or Load Curtailment

The study included an optimal load shed analysis to estimate the amount of hypothetical load shed needed to resolve the reliability issues. To fully address all the thermal overloads, the amount of contracted demand response needed was estimated to be 75 MW as an alternative to Michoud Unit #3. The calculated demand response represents the minimum amount of load curtailment needed to address the worst contingencies and is dependent upon the location where the load shed should occur.

d. Transmission Projects

Entergy proposed to mitigate the thermal overloads by expediting the following projects to increase rating of the lines to 779 MVA. Additionally Entergy has identified upgrades to address voltage issues cause by NERC Category P2 contingencies. These projects are currently submitted as Target Appendix A projects in MTEP15 cycle.

- P4779: Nine Mile to Derbigny 230 KV Upgrade – expected ISD 6/1/2016
- P4780: Nine Mile to Napoleon 230 KV Upgrade – expected ISD 6/1/2016
- P9300: Franklin 115 Bus Reconfiguration – expected ISD 6/1/2016

VIII. CONCLUSION

After being reviewed for the power system reliability impacts as provided for under Section 38.2.7 of the MISO's Open Access Transmission, Energy & Operating Reserve Markets Tariff ("Tariff"), Michoud Unit 3 was determined to be required as a System Support Resource unit due to the remaining thermal and voltage violations.

Entergy has proposed three transmission projects, which are required to be in service before the June 1, 2016 retirement date, to address the issues identified in the analysis. These projects include:

P4779 – Nine Mile to Derbigny 230 KV, ISD 6/1/2016 (MTEP15 Target Appendix A)

P4780 – Nine Mile to Napoleon 230 KV, ISD 6/1/2016 (MTEP15 Target Appendix A)

P9300 – Franklin 115kV Bus Reconfiguration, ISD 6/1/2016 (MTEP15 Target Appendix A)

Entergy has indicated that it will accelerate all three projects to complete the work before the retirement of Michoud Unit 3 (June 1, 2016).

IX. APPENDICES

Appendix A: Results of Steady-State AC Contingency Analysis for Michoud Unit 3 Retirement

Appendix B: Results of Steady-State AC Contingency Analysis for recurring outages of Waterford Unit 3 Following Michoud 3 Retirement

Appendix A

Steady-State AC Contingency Analysis Results

Appendix A - MISO Michoud Unit 3 Attachment Y Study
Table 1 - Compare Branch Results

			Michoud 3 Off			Michoud 3 On					
Scenario	Limiting Element	Rating	Cont. Flow		Loading	BF.con.flow		Loading	OTDF	Contingency	Comments
2016SH	335569 6ST_GABRIEL%230.00 - 335573 6AAC_CORP 230.00 1	685	685.9		100.13	636.9		92.98	9.07	[REDACTED]	[REDACTED]
2016SH	336402 6MIDTNB 230.00 - 336434 6ALMON! 230.00 1	441	514.8		116.73	347.3		54.2	31.02	[REDACTED]	[REDACTED]
2016SH	336434 6ALMON! 230.00 - 336436 6CURRN 230.00 1	441	458.8		104.04	293.2		66.5	30.67	[REDACTED]	[REDACTED]
2016SH	336552 3NORFIELD+ 115.00 - 336553 3MALLALIEU+ 115.00 1	199	213.6		107.34	189		94.97	4.56	[REDACTED]	[REDACTED]
2016SH	336553 3MALLALIEU+ 115.00 - 336554 3BROOKHAVEN!115.00 1	199	231.5		116.33	208.6		104.82	4.24	[REDACTED]	[REDACTED]
2016SUM	336198 6SPORT% 230.00 - 336400 6JOLIET! 230.00 1	641	666.2		103.93	489.9		76.43	32.65	[REDACTED]	[REDACTED]
2016SUM	336236 3PRSTAP 115.00 - 336406 3AVE C! 115.00 1	221	227.9		103.12	183.2		82.9	8.28	[REDACTED]	[REDACTED]
2016SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	641		100	516.6		80.59	23.04	[REDACTED]	[REDACTED]
2016SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	641		100	516.6		80.59	23.04	[REDACTED]	[REDACTED]
2016SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	647.4		101	524.6		81.84	22.74	[REDACTED]	[REDACTED]
2016SUM	336250 69MILE% 230.00 - 336432 6DERBI! 230.00 1	641	663.8		103.56	534.3		82.06	25.52	[REDACTED]	[REDACTED]
2016SUM	336402 6MIDTNB 230.00 - 336434 6ALMON! 230.00 1	441	554.8		125.8	387.5		87.87	30.98	[REDACTED]	[REDACTED]

Appendix A - MISO Michoud Unit 3 Attachment Y Study
Table 1 - Compare Branch Results

			Michoud 3 Off			Michoud 3 On					
Scenario	Limiting Element	Rating	Cont. Flow		Loading	BF.con.flow		Loading	OTDF	Contingency	Comments
2016SUM	336434 6ALMON! 230.00 - 336436 6CURRN 230.00 1	441	483.4		109.61	294.6		66.8	34.96	[REDACTED]	[REDACTED]
2016SUM	336526 3ARLINGTON+ 115.00 - 336559 3FRANKLIN! 115.00 1	161	167.5		104.04	150.9		93.73	3.07	[REDACTED]	[REDACTED]
2016SUM	336552 3NORFIELD+ 115.00 - 336553 3MALLALIEU+ 115.00 1	199	206.8		103.92	184		92.46	4.22	[REDACTED]	[REDACTED]
2016SUM	336553 3MALLALIEU+ 115.00 - 336554 3BROOKHAVEN!115.00 1	199	227.4		114.27	204.3		102.66	4.28	[REDACTED]	[REDACTED]
2016SUM	337368 8MT_OLIVE% 500.00 - 509366 LAYFLD8 500.00 1	1200	1228		102.33	1148.6		95.72	14.7	[REDACTED]	[REDACTED]
2016SUM	337368 8MT_OLIVE% 500.00 - 509366 LAYFLD8 500.00 1	1200	1218.9		101.58	1136.1		94.67	15.33	[REDACTED]	[REDACTED]
2019SUM	335569 6ST_GABRIEL%230.00 - 335573 6AAC_CORP 230.00 1	685	688		100.44	641		93.58	8.7	[REDACTED]	[REDACTED]
2019SUM	336198 6SPORT% 230.00 - 336400 6JOLIET! 230.00 1	641	672.9		104.98	489.9		76.43	33.89	[REDACTED]	[REDACTED]
2019SUM	336236 3PRSTAP 115.00 - 336406 3AVE C! 115.00 1	221	232		104.98	183.2		82.9	9.04	[REDACTED]	[REDACTED]
2019SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	646.7		100.89	518.9		81	23.67	[REDACTED]	[REDACTED]
2019SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	646.7		100.89	516.6		80.59	24.09	[REDACTED]	[REDACTED]
2019SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	643.3		100.36	523.4		81.65	22.2	[REDACTED]	[REDACTED]

Appendix A - MISO Michoud Unit 3 Attachment Y Study
Table 1 - Compare Branch Results

			Michoud 3 Off			Michoud 3 On					
Scenario	Limiting Element	Rating	Cont. Flow		Loading	BF.con.flow		Loading	OTDF	Contingency	Comments
2019SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	654.4		102.09	524.6		81.84	24.04	[REDACTED]	[REDACTED]
2019SUM	336250 69MILE% 230.00 - 336428 6NAPOL 230.00 1	641	642.4		100.2	512.9		80.02	23.09	[REDACTED]	[REDACTED]
2019SUM	336250 69MILE% 230.00 - 336432 6DERBI! 230.00 1	641	669.6		104.46	298.8		46.6	68.67	[REDACTED]	[REDACTED]
2019SUM	336402 6MIDTNB 230.00 - 336434 6ALMON! 230.00 1	441	559.5		126.87	349.5		79.25	38.89	[REDACTED]	[REDACTED]
2019SUM	336434 6ALMON! 230.00 - 336436 6CURRN 230.00 1	441	486.9		110.41	323.2		73.29	30.31	[REDACTED]	[REDACTED]

Appendix A - MISO Michoud Unit 3 Attachment Y Study
Table 2 - Compare Voltage Results

							Michoud 2 Off		Michoud 2 On				
Scenario	Bus Number	Bus Name	kV	Area	LV Limit	HV Limit	Cont. Voltage	Base Voltage	BF.con.Vol	BF.base.Vol	Delta Volt %	Contingency	Comments
2016SUM	336552	3NORFIELD+ 115.00	115	351	0.92	1.05	0.9088		0.919		-1.02	[REDACTED]	[REDACTED]
2016SUM	336553	3MALLALIEU+ 115.00	115	351	0.92	1.05	0.898		0.909		-1.1	[REDACTED]	[REDACTED]
2016SUM	336553	3MALLALIEU+ 115.00	115	351	0.92	1.05	0.915		0.9254		-1.04	[REDACTED]	[REDACTED]
2016SUM	336554	3BROOKHAVEN!115.00	115	351	0.92	1.05	0.8912		0.9029		-1.17	[REDACTED]	[REDACTED]
2016SUM	336554	3BROOKHAVEN!115.00	115	351	0.92	1.05	0.9099		0.921		-1.11	[REDACTED]	[REDACTED]
2016SUM	336556	3W.BROOKHAVN115.00	115	351	0.92	1.05	0.8852		0.897		-1.18	[REDACTED]	[REDACTED]
2016SUM	336557	3CALIFORNIA 115.00	115	351	0.92	1.05	0.8841		0.8959		-1.18	[REDACTED]	[REDACTED]
2016SUM	336558	3VAUGHN+ 115.00	115	351	0.92	1.05	0.8824		0.8942		-1.18	[REDACTED]	[REDACTED]
2016SUM	336770	3WESSON 115.00	115	351	0.92	1.05	0.8934		0.9053		-1.19	[REDACTED]	[REDACTED]
2016SUM	336770	3WESSON 115.00	115	351	0.92	1.05	0.9107		0.9219		-1.12	[REDACTED]	[REDACTED]
2016SUM	336771	3JAMES RD+ 115.00	115	351	0.92	1.05	0.9019		0.9136		-1.17	[REDACTED]	[REDACTED]
2016SUM	336771	3JAMES RD+ 115.00	115	351	0.92	1.05	0.9167		0.9278		-1.11	[REDACTED]	[REDACTED]

Appendix A - MISO Michoud Unit 3 Attachment Y Study
Table 2 - Compare Voltage Results

							Michoud 2 Off		Michoud 2 On				
Scenario	Bus Number	Bus Name	kV	Area	LV Limit	HV Limit	Cont. Voltage	Base Voltage	BF.con.Vol	BF.base.Vol	Delta Volt %	Contingency	Comments
2016SUM	336772	3HAZLHURST 115.00	115	351	0.92	1.05	0.9052		0.9167		-1.15	[REDACTED]	[REDACTED]
2016SUM	336772	3HAZLHURST 115.00	115	351	0.92	1.05	0.9192		0.9302		-1.1	[REDACTED]	[REDACTED]
2016SUM	336773	3COPIAH+ 115.00	115	351	0.92	1.05	0.9057		0.9172		-1.15	[REDACTED]	[REDACTED]
2016SUM	336773	3COPIAH+ 115.00	115	351	0.92	1.05	0.9196		0.9305		-1.09	[REDACTED]	[REDACTED]
2016SUM	336774	3GALLMAN 115.00	115	351	0.92	1.05	0.9107		0.9218		-1.11	[REDACTED]	[REDACTED]

Appendix B

Analysis of Load Shed Risk with Waterford Unit 3 Outage

Appendix B - Analysis of Waterford Unit 3 Outage with Michoud 3 Retirement
Table 1 - Thermal Analysis Results

Year_Load	Cont Label	Cont Definition	Limiting Element	Rating	OFF_Cont_MVA	OFF_Load_Pct	ON_Cont_MVA	ON_Load_Pc	OTDF	Potential Load Shed	Comments
2016SH	[REDACTED]	[REDACTED]	335569 6ST_GABRIEL%230.00 - 335573 6AAC_CORP 230.00 1	685	692.8	101.14	643.9	94	9.06	**15.28**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	335573 6AAC_CORP 230.00 - 335574 6LICAR% 230.00 1	685	689.9	100.72	640.2	93.46	9.2	**26.04**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	335569 6ST_GABRIEL%230.00 - 335573 6AAC_CORP 230.00 1	685	701	102.34	650.5	94.96	9.35	**26.04**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	335573 6AAC_CORP 230.00 - 335574 6LICAR% 230.00 1	685	686.3	100.19	636.9	92.98	9.15	**20.44**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	335569 6ST_GABRIEL%230.00 - 335573 6AAC_CORP 230.00 1	685	697.4	101.81	647.3	94.5	9.28	**20.44**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336434 6ALMON! 230.00 - 336436 6CURRN 230.00 1	441	444.8	100.86	280	63.5	30.52	**161.11**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336402 6MIDTNB 230.00 - 336434 6ALMON! 230.00 1	441	500.8	113.56	334.8	75.9	30.74	**161.11**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336551 3MCCOMB! 115.00 - 336552 3NORFIELD+ 115.00 1	199	213.7	107.39	191.4	96.18	4.13	**191.93**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336552 3NORFIELD+ 115.00 - 336553 3MALLALIEU+ 115.00 1	199	230.9	116.03	207.9	104.47	4.26	**191.93**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336553 3MALLALIEU+ 115.00 - 336554 3BROOKHAVEN!115.00 1	199	249	125.13	228.3	114.72	3.83	**191.93**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336111 3AMITE! 115.00 - 336517 3GILLSBURG+ 115.00 1	112	116.3	103.84	95.3	85.1	3.89	**191.93**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336515 3LIBERTY! 115.00 - 336517 3GILLSBURG+ 115.00 1	115	123.8	107.65	102.1	88.8	4.02	**191.93**	[REDACTED]

Appendix B - Analysis of Waterford Unit 3 Outage with Michoud 3 Retirement
Table 2 - Voltage Analysis Results

Year_Load	Cont Label	Cont Definition	Bus Number	Bus Name	kV	Model Area	LV Limit	HV Limit	Cont_Level_OFF	Cont_Level_ON	Delta Volt %	Potential Load Shed	Comments
2016SH	[REDACTED]	[REDACTED]	336080	3CLOVEL 115.00	115	351	0.92	1.05	0.9055	0.9853	-7.98	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336083	3FOURCHN 115.00	115	351	0.92	1.05	0.8894	1.0009	-11.15	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336081	3GMEADW! 115.00	115	351	0.92	1.05	0.9176	0.9964	-7.88	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336082	3LEEVLL 115.00	115	351	0.92	1.05	0.9004	1.0042	-10.38	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336080	3CLOVEL 115.00	115	351	0.92	1.05	0.9055	0.9853	-7.98	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336083	3FOURCHN 115.00	115	351	0.92	1.05	0.8894	1.0009	-11.15	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336081	3GMEADW! 115.00	115	351	0.92	1.05	0.9176	0.9964	-7.88	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336082	3LEEVLL 115.00	115	351	0.92	1.05	0.9004	1.0042	-10.38	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336080	3CLOVEL 115.00	115	351	0.92	1.05	0.9055	0.9853	-7.98	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336083	3FOURCHN 115.00	115	351	0.92	1.05	0.8894	1.0009	-11.15	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336081	3GMEADW! 115.00	115	351	0.92	1.05	0.9176	0.9964	-7.88	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336082	3LEEVLL 115.00	115	351	0.92	1.05	0.9004	1.0042	-10.38	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336080	3CLOVEL 115.00	115	351	0.92	1.05	0.9055	0.9853	-7.98	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336083	3FOURCHN 115.00	115	351	0.92	1.05	0.8894	1.0009	-11.15	**10.71**	[REDACTED]

Appendix B - Analysis of Waterford Unit 3 Outage with Michoud 3 Retirement
Table 2 - Voltage Analysis Results

Year_Load	Cont Label	Cont Definition	Bus Number	Bus Name	kV	Model Area	LV Limit	HV Limit	Cont_Level_OFF	Cont_Level_ON	Delta Volt %	Potential Load Shed	Comments
2016SH	[REDACTED]	[REDACTED]	336081	3GMEADW! 115.00	115	351	0.92	1.05	0.9176	0.9964	-7.88	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336082	3LEEVLL 115.00	115	351	0.92	1.05	0.9004	1.0042	-10.38	**10.71**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336083	3FOURCHN 115.00	115	351	0.92	1.05	0.8908	1.0006	-10.98	**10.69**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336081	3GMEADW! 115.00	115	351	0.92	1.05	0.9188	0.9961	-7.73	**10.69**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336082	3LEEVLL 115.00	115	351	0.92	1.05	0.9018	1.0039	-10.21	**10.69**	[REDACTED]
2016SH	[REDACTED]	[REDACTED]	336080	3CLOVEL 115.00	115	351	0.92	1.05	0.9067	0.985	-7.83	**10.69**	[REDACTED]

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**))))**	**DOCKET NO. UD-16-________**

DIRECT TESTIMONY

OF

SHAUNA LOVORN-MARRIAGE

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JUNE 2016

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Shauna Lovorn-Marriage. I am employed by Entergy Services, Inc. ("ESI") as Director, Regulatory Filings. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

A. Qualifications

Q2. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I have a Masters of Business Administration from the University of New Mexico and a Bachelors of Business Administration in Accounting from Western New Mexico University. I began my career with ESI as Director of Regulatory Filings December of 2014. In my role, I am responsible for the preparation of and support of regulatory filings for all regulated Entergy Operating Companies. Prior to my career at ESI, I held various positions over fourteen years at PNMR Services Company, a subsidiary of PNM Resources, which is a utility holding company in New Mexico. Those positions at PNMR Services Company included Director of Strategic Financial Planning, Director of Cost of Service and Corporate Budget, and Director of Cost of Service and Pricing. I have submitted testimony on behalf of PNM Resource subsidiaries before the New Mexico Public Regulatory Commission, the Public Utility Commission of Texas, and the Federal Energy Regulatory Commission. I have provided a list of the proceedings in which I have submitted testimony in Exhibit SLM-1.

B. Purpose of Testimony

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am testifying before the Council for the City of New Orleans ("CNO" or the "Council") on behalf of Entergy New Orleans, Inc. ("ENO" or "Company") in support of a proposed combustion turbine ("CT") facility in Orleans Parish (the "Project" or "NOPS").

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses the regulatory and ratemaking issues that the Company is requesting the Council determine, so that ENO may initiate and successfully complete the construction of NOPS at the lowest reasonable cost. Specifically, I:

- discuss the approvals and findings necessary before commencing construction of NOPS and their importance;
- discuss ENO's compliance and/or intent to comply with any applicable Council Orders concerning the construction of NOPS;
- discuss why approval of NOPS is in the public interest; and
- discuss the proposed plan by which the Council and its Advisors can monitor the progress of the construction of NOPS.

Q5. WILL YOU BRIEFLY SUMMARIZE YOUR CONCLUSIONS?

A. Yes. My conclusions are as follows:

- The approval of ENO's request to commence construction of the Project is consistent with all applicable Council requirements.
- In this proceeding, the Council is being asked to determine whether the commencement of construction of NOPS is in the public interest.
- Based on the information presented in the Direct Testimony accompanying ENO's Application, NOPS is the lowest reasonable cost resource considering risks available to meet ENO's long term needs for overall generation and to aid in meeting ENO's immediate need for peaking and reserve generation. NOPS will also bolster reliability and resiliency in New Orleans. Therefore, it is in the public interest and reasonable and prudent for ENO to commence construction of the Project.
- The proposed Monitoring Plan provides sufficient and timely information for the Council and its Advisors to determine whether construction of NOPS should continue in light of information that becomes available after commencement of construction and, therefore, is in the public interest.

II. REGULATORY APPROVALS AND FINDINGS

Q6. WHEN WAS THE LAST TIME THE COUNCIL APPROVED THE CONSTRUCTION OF A GENERATING UNIT BY THE COMPANY?

A. This proceeding presents possibly the first time in more than thirty years that the Company has asked the Council to approve the construction of a generating unit by ENO. In recent years, the Council approved ENO's entering into a purchased power agreement to purchase capacity and energy from Ninemile 6, which Entergy

Louisiana, LLC ("ELL") constructed. Last year, the Council approved the purchase of Union Power Station ("Power Block 1"), which was already in commercial operation.

Q7. WHY ARE THE REQUESTED REGULATORY APPROVALS AND FINDINGS IMPORTANT TO BOTH THE COMPANY AND THE COUNCIL?

A. The requested regulatory approvals and findings are important to ENO because they will give the Company certainty that it will have a reasonable opportunity to recover its prudently incurred costs associated with the construction of NOPS. Without that certainty, the Company could not reasonably undertake the investment necessary to construct NOPS.

From the Council's perspective, determining whether the requested regulatory approvals and findings should be granted provides benefits to customers as well. The determination gives the Council an opportunity to ensure, in advance, that ENO's capital is used on an investment that is prudent and consistent with the public interest.

Q8. PLEASE LIST THE REGULATORY APPROVALS AND FINDINGS THAT ENO SEEKS IN CONNECTION WITH THE PROJECT.

A. In its Application, ENO is seeking the following approvals and findings by this Council:

1. that the construction of NOPS serves the public convenience and necessity and is in the public interest and therefore prudent;

2. that the Company's investments made pursuant to a public interest determination by the Council are presumed prudent and eligible for recovery from customers, and that the Company will have a full and fair opportunity to recover all prudently-incurred costs of the Project;
3. that the proposed Monitoring Plan is reasonable, is in the public interest and is, therefore, approved;
4. that the proposed Cost Recovery Plan that would take effect after the plant goes into service, which is discussed in the direct testimony of Mr. Todd, is reasonable, is in the public interest and is, therefore, approved;
5. that, with respect to the Project described in the Application, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions; and
6. that the Council develop and implement appropriate procedures to facilitate a Council decision on the Application no later than its January 2017 Meeting of the CNO Utility, Cable, Telecommunications and Technology Committee.

Q9. WHY ARE THE FIRST TWO APPROVALS LISTED ABOVE IMPORTANT?

A. Those approvals are important because they will give ENO the certainty that its decision to commence construction of NOPS is prudent and that no one will be able to later claim that ENO's entire investment in NOPS should be disallowed because the decision to commence construction of NOPS was imprudent.

This proceeding gives the Council, the Advisors, and any other parties to the proceeding the opportunity to review fully the planning process that has resulted in ENO's conclusion to construct NOPS. At the end of the proceeding, the Council will determine whether the commencement of construction of NOPS is in the public interest and issue a final decision on the matter.

Q10. DOES THAT MEAN THAT THE COUNCIL IS PRECLUDED FROM FURTHER REVIEW OF THE CONSTRUCTION OF NOPS?

A. No. The Council will continue to monitor the progress of the NOPS construction and will ensure that continuing construction to completion remains in the public interest in the event that circumstances change significantly after initial approval. The proposed Monitoring Plan, discussed later in my testimony, is intended to facilitate the Council's review of the progress of NOPS' construction. In addition, after NOPS is completed, the Council may review the prudence of ENO's management of the construction contract and the costs incurred.

Q11. WHY IS THE APPROVAL OF THE PROPOSED MONITORING PLAN IMPORTANT?

A. The approval of the Monitoring Plan is important because it gives the Council and ENO certainty regarding the scope of information and analyses to be provided, as well as the timetable by which to provide that information.

Q12. WHY IS THE APPROVAL OF THE PROPOSED COST RECOVERY PLAN IMPORTANT?

A. The approval of the cost recovery plan is important because it gives ENO certainty that it will have an opportunity to recover the prudently-incurred costs associated with NOPS on a timely basis and approval gives the Council certainty that the recovery of such costs will be just and reasonable. In the past, the Council has allowed timely recovery of the costs associated with new resources obtained for the benefit of ENO's customers, such as Power Block 1 of the Union Power Station and the PPA with respect to Ninemile 6. Such rate treatment provides an incentive for ENO to continue to undertake large investments or obligations in order to secure benefits for its customers.

Q13. WHEN DOES ENO REQUEST THE COUNCIL GRANT THE NECESSARY REGULATORY APPROVALS?

A. ENO asks that the Council take the steps needed to establish a Procedural Schedule such that the Council would issue a decision on this Application no later than January 31, 2017. This timetable will provide adequate time for the Council, its Advisors and any stakeholders to review and provide comment on the Application and the Project, while also permitting ENO to commence construction in order to achieve substantial completion on or before October 1, 2019, as discussed in the testimony of Mr. Jonathan Long.

III. COMPLIANCE WITH COUNCIL RESOLUTIONS

Q14. PLEASE DISCUSS ANY SPECIFIC COUNCIL REQUIREMENTS APPLICABLE TO THE PROJECT.

A. ENO's activities related to NOPS comply with Resolution R-15-524, which the Council adopted on November 5, 2015 in Docket Nos. UD-13-03 and UD-13-04, wherein the Council approved the proposed settlement terminating the Entergy System Agreement. As a condition of that approval, Resolution R-15-524 directed ENO to "use reasonable diligent efforts to pursue the development of at least 120 MW of new-build peaking generation capacity within the City of New Orleans."[1] That Resolution also emphasizes a commitment for ENO "to use diligent efforts to have at least one future generation facility located in the City of New Orleans." *Id*. The Project, if approved, would comply with each of these directives from the Council.

R-15-524 also directed ENO to, "fully evaluate Michoud or Paterson, along with any other appropriate sites in the City of New Orleans, as the potential site for a combustion turbine ("CT") or other peaking unit to be owned by ENO." *Id*. The site selection evaluation that ENO undertook for the Project, which is described in the testimony of ENO's witness Mr. Seth Cureington, complies with these directives.

[1] See R-15-524 at pg. 12.

Q15. IS THE CONSTRUCTION OF THE PROJECT CONSISTENT WITH THE INTEGRATED RESOURCE PLAN REQUIRED BY COUNCIL RESOLUTION R.-08-295?

A. Yes. I would note that after a nearly two-year process, ENO has filed its Final 2015 Integrated Resource Plan ("IRP") in Docket No. UD-08-02 on February 1, 2016. ENO's witness Mr. Seth Cureington explains that the proposed Project is consistent with ENO's Final 2015 IRP.

IV. THE PUBLIC INTEREST

Q16. YOU INDICATED PREVIOUSLY THAT YOU WOULD DISCUSS WHETHER, IN YOUR OPINION, THE CONSTRUCTION OF NOPS IS IN THE PUBLIC INTEREST. WHAT IS THE PUBLIC INTEREST?

A. The public interest is that which is thought to best serve everyone; it is the common good. If the net effect of a decision is believed to be positive or beneficial to society as a whole, it can be said that the decision serves the "public interest."

Public utilities in general, and electric utilities in particular, affect nearly all elements of society. Public utilities have the ability to influence the cost of production of the businesses that are served by them, to affect the standard of living of their customers, to affect employment levels in the areas they serve, and to affect the interests of their investors. In sum, public utilities affect the general economic activity in the state.

In determining whether a particular decision or policy is in the public interest, there is no immutable law or principle that can be applied. It is recognized that public interest cannot simply be defined as lower prices. For example, if lower prices are achieved through a reduction in the reliability or quality of service, it may very well be perceived that the lower prices have not advanced the public interest. Similarly, higher prices might not produce detriments. For example, if an existing price is low due to a cross-subsidy, removing that subsidy would raise that price, but doing so would not necessarily be detrimental. The Louisiana Supreme Court reached just such a conclusion in *City of Plaquemine v. Louisiana Public Service Commission* 282 So. 2d 440 (1973), when it found that:

> The entire regulatory scheme, including increases as well as decreases in rates, is indeed in the public interest, designed to assure the furnishing of adequate service to all public utility patrons at the lowest reasonable rates consistent with the interest both of the public and of the utilities.
>
> Thus the public interest necessity in utility regulation is not offended, but rather served by reasonable and proper rate increases notwithstanding that an immediate and incidental effect of any increase is improvement in the economic condition of the regulated utility company.[2]

Objective measurement of how a decision affects the public interest is problematic at best. For the past fifty or more years, regulatory decision-making has been tested in the courts by a balancing-of-interests standard. In these cases, beginning with *Federal Power Commission v. Hope Natural Gas Company* 320 U.S. 591, 660 (1944), the courts have found that if the regulatory body's decision reflected a reasonable balancing of customer and investor interests, the decision was to be affirmed as just and reasonable.

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2 *Id*. at 442-43.

In sum, determining whether a decision is in the "public interest" requires a balancing of the various effects of a particular course of action measured subjectively over the longer run. Whether a course of action is in the public interest will depend upon factors that are potentially quantifiable on an estimated basis, such as likely changes in costs, as well as upon other factors that are not quantifiable, such as the effect of that course of action on the robustness of a competitive market. Finally, while witnesses can provide facts and opinions that bear on this issue, the decision-maker, the Council, must ultimately determine whether the construction is in the public interest.

Q17. IN YOUR OPINION, IS THE CONSTRUCTION OF NOPS IN THE PUBLIC INTEREST?

A. Yes. My opinion is based on a number of factors discussed in detail by other witnesses. As Mr. Seth Cureington's testimony demonstrates, ENO faces an overall capacity need as well as a substantial and significant need for local peaking and reserve capacity resources, which the Council has noted is particularly critical following the deactivation of the Michoud plant and the termination of the System Agreement.[3] Mr. Cureington's analysis indicates NOPS is the most economical resource available for meeting a large portion of ENO's projected long-term peaking and reserve capacity needs as well as ENO's overall capacity need. As Mr. Jonathan Long notes, this results from NOPS utilizing CT technology that provides significantly lower cost per unit of output, as well better operational characteristics,

[3] See R-15-524 at pg. 12.

than other technologies. Moreover, as Mr. Cureington discusses, NOPS provides additional economic security for ENO and its customers because NOPS can act as a hedge against potentially volatile market prices.

In addition to the economic merits of the Project, the location of NOPS provides additional benefits that make its construction consistent with the public interest. Mr. Jonathan Long discusses that locating NOPS at the Michoud site allows the ENO and its customers to benefit from certain efficiencies, such as the utilization of existing infrastructure at the site. Moreover, as discussed by Mr. Charles Long. Locating NOPS within the City of New Orleans also bolsters the reliability and resiliency of power in the City, both generally and in the event of major storms - including hurricanes. Siting NOPS at the former Michoud location also fulfills the Council's recent directives concerning the placement of a CT facility to be used for peaking generation within the City of New Orleans, as I discussed earlier in my testimony.

Finally, NOPS is expected to have significant economic benefits for Orleans Parish residents and businesses. As discussed by ENO's witness Charles Rice, NOPS is anticipated to have a significant positive effect on the economy of Orleans Parish. For all these reasons, it is my opinion that NOPS is in the public interest.

V. PROPOSED MONITORING PLAN

Q18. WOULD YOU NOW DISCUSS THE PROPOSED MONITORING PROCEDURES AND REPORTS?

A. Yes. ENO proposes a Monitoring Plan, an outline of which is attached as Exhibit SLM-2. The Proposed Monitoring Plan contemplates quarterly progress reports providing detailed information on the status of NOPS, its costs, and other activities that are critical to completing the Project in a timely manner. It is not contemplated that there would be any litigation concerning these reports, and, other than informal exchanges of information between ENO and the Advisors, there would be no formal discovery process. ENO is requesting that the Council require the Advisors to acknowledge receipt of each quarterly report in writing and submit any questions regarding the report within 30 days.

Q19. DO ENO AND THE ADVISORS HAVE SOME EXPERIENCE WITH A MONITORING PLAN SIMILAR TO THE ONE PROPOSED IN THIS PROCEEDING?

A. Yes. In Council Resolution R-12-29, dated February 2, 2012, the Council approved the prudence of ENO's exercising its right of first refusal to enter into a PPA to purchase a 20% share of the capacity and energy from Ninemile 6. As part of the Agreement in Principle approved in that resolution, ENO agreed to provide Advisors the quarterly progress reports, similar to the reports contemplated by the Proposed Monitoring Plan, and hold an in-person meeting or conference call on such reports.

Q20. WOULD THE PROPOSED MONITORING PLAN PROVIDE THE COUNCIL AND ITS ADVISORS INFORMATION CONCERNING WHETHER THE PROJECT SHOULD BE COMPLETED?

A. Yes, it would. Once the Council has approved commencement of construction of NOPS, any issues regarding the propriety of the continuation of that construction would be a result of a subsequent change in circumstances or information learned after the commencement of construction. Such information could be the discovery of a new technology that would provide benefits that outweighed the completion of Project or a change in the cost to complete or operate the Project that renders it uneconomic. In all cases, a decision to continue construction of NOPS would be dependent on an analysis of the incremental cost to complete and operate NOPS as of that point in time during construction versus the incremental cost of available alternatives.

In this context, the Proposed Monitoring Plan will serve as an "early warning system," and ENO will include in the quarterly monitoring reports an affirmation as to whether continuing the Project is, in their opinion, in the public interest.

Q21. WHAT PROCESS WOULD BE USED TO CEASE CONSTRUCTION OR CANCEL NOPS?

A. In the event ENO believes it to be in the public interest to cease construction and cancel the Project, ENO would make a filing in this proceeding seeking the Council's approval of that recommendation. In that filing, ENO would request a Council decision on that matter as soon as practical. ENO's Application seeks approval of this procedure.

Q22. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF Orleans

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SHAUNA LOVORN-MARRIAGE**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Shauna Lovorn-Marriage

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 17th DAY OF JUNE, 2016

NOTARY PUBLIC

My commission expires: at death

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life

Listing of Previous Testimony Filed by Shauna Lovorn-Marriage

DATE	TYPE	JURISDICTION	DOCKET NO.
March 2010	Direct	PUCT	38012
October 2010	Direct	FERC	ER11-1915
June 2010	Direct	NMPRC	10-00086-UT
January 2012	Direct	NMPRC	12-00007-UT
February 2012	Supplemental Direct	NMPRC	12-00007-UT
May 2012	Rebuttal	NMPRC	12-00007-UT
May 2012	Supplemental Rebuttal	NMPRC	12-00007-UT
January 2013	Direct	NMPRC	13-00004-UT
February 2013	Direct	NMPRC	12-00007-UT
March 2013	Supplemental Direct	NMPRC	13-00004-UT

Monitoring Procedures and Reports Related to the New Orleans Power Station Project

1. *Monitoring Procedures and Reports*

ENO will submit quarterly progress reports to the Advisors within 45 days of the close of the calendar quarter. The contents of the report may be largely confidential, with the exception of a non-confidential summary. Within 30 days of the submission of the quarterly monitoring report, the Advisors will acknowledge receipt of the report, in writing, and provide any questions regarding the report. ENO also will provide to the Advisors informal reports of any significant developments occurring between the more formal quarterly reports. ENO will arrange for the Advisors to undertake site visits once or twice per year, or as deemed necessary.

2. *Quarterly Report Elements*

The quarterly progress monitoring reports will include the following information:

<u>Summary of Status of Project Schedule</u>

An overview of major items accomplished (such as construction or procurement activities):

1. Description of any changes to planned activities (or milestones) that have implications for project schedule or task sequencing;
2. Overall project schedule status; and
3. Project Gantt Chart showing major project milestones.

The information in this section will be sufficiently detailed to understand the relationship between the current schedule and the original schedule, including any changes to major project milestones.

Project Budget Status

Project reports will also include updates as to the status of the budget of the Project. Each report will provide a table that identifies (a) the original cost estimate; (b) expenditures to date; (c) estimated future spending; (d) cost estimate revisions (due to change orders or other reasons); and (e) any budget variance. These data will be broken down as (a) EPC payments (b) Other vendors/expenses; (c) Entergy project management; (d) Indirect loaders; (e) Allowance for Funds Used During Construction ("AFUDC"); (f) project contingency; (g) transmission interconnection to switchyard; and (h) transmission costs for network resource interconnection service.

Project Financing

This section of the report will provide a detailed monthly tracking of AFUDC costs. It will include tables with the projected AFUDC accruals over the entire construction period consistent with the Regulatory Approval Plan and cumulative totals. Any changes in the life of Project AFUDC accruals estimate (*e.g.*, due to change in project schedule or costs) will be identified. AFUDC accruals will cease when the Project enters service. This section of the report also will track progress in ENO's securities issuances for financing during the period of the Project, as well as replacement of maturing debt. ENO will provide a summary of securities issuances or financings recently accomplished and expected in the near term. This will include the identification of the principal terms of new financings. In addition, ENO will provide a copy of any new credit rating reports pertaining to ENO, and a copy of any presentation to credit rating agencies.

Business Issues

This section will provide for the identification of other business issues pertinent to the Project. It will include but not be limited to material business disputes with contractors, force majeure issues, labor problems or disputes, and any issues or problems associated with local government or the local community. This will also include any important amendments to the CB&I EPC contract.

Transmission

This section will discuss progress and cost estimates relating to upgrades to interconnection the Project with the switchyard as well as obtaining NRIS service for the Project.

Safety

ENO will provide, in each progress report, tables reporting the recordable incident rate ("IR") and lost workday injury and illness rate ("LWDII") information for the Project or similar information relating to work-related safety statistics. This will be provided by month and cumulatively for the entire construction period for ENO, CB&I and the project subcontract workers.

Environmental Compliance

The progress report will identify any environmental permitting or compliance issues that arise and that could affect the project. Environmental issues discussed in this section will include any permit modification or new requirements. In addition, ENO will report on new environmental laws or regulations that have the potential to affect the Project

Additional Matters

In addition to the information described above, the quarterly report will include an Executive Summary highlighting progress on the project, significant changes to the project plan and other notable developments. To the extent not provided elsewhere, ENO will include the following information in its report:

(1) updates in ENO's forecasted cost of natural gas;

(2) information regarding material changes in the cost of alternative technology that could serve the same supply role;

(3) material changes in the cost to complete the project;

(4) material incremental changes in the cost of environmental compliance; and

(5) an affirmation as to whether continuing construction of the Project remains in the public interest.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-_____**

DIRECT TESTIMONY

OF

ROBERT A. BREEDLOVE

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016

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LIST OF EXHIBITS

I. INTRODUCTION AND PURPOSE

A. Qualifications

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Robert A. Breedlove. My business address is 10055 Grogan's Mill Road, The Woodlands, Texas 77380.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, Inc. ("ESI") as Director of Plant Support in Fossil Operations. In that capacity, I am responsible for providing strategic support for Entergy's Fossil generation fleet. My responsibilities include commercial management of long-term services agreements covering combustion turbines ("CT") owned by the Entergy Operating Companies.[1]

Q3. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE AND EDUCATION.

A. In 1996, I earned a Bachelor of Science degree in Mechanical Engineering from Mississippi State University. In 2008, I was awarded a Master of Business Administration degree from Tulane University.

Between 1996 and 2000, I was employed by a major U.S.-based petrochemical company in a project engineering role for development of electric power and utilities projects throughout the company's facilities worldwide. In 2000, I

[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans, Inc. ("ENO or the "Company"), and Entergy Texas, Inc. ("ETI").

joined Entergy as a Plant Engineer at one of our gas turbine facilities. From 2004 through 2010, I served as Process Superintendent and later Production Superintendent for several Entergy plants, including three gas turbine-powered plants in northern Louisiana. In 2010, I was named asset manager for ELL's Acadia Power Block Two. In 2012, I was named Fleet Maintenance Manager with responsibility for managing strategic initiatives for Entergy's fleet of gas turbine plants. In 2016, I was named Director of Plant Support in Fossil Generation.

Q4. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am testifying before the Council of the City of New Orleans ("CNO" or the "Council") on behalf of ENO in support of the proposed Project.

B. <u>Purpose of Testimony</u>

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony supports the Company's Application in this proceeding, which seeks, among other things, approval to construct New Orleans Power Station ("NOPS"), an advanced CT with a nominal size[2] of 226 MW at the Michoud facility in New Orleans, Louisiana. Generally, my testimony addresses three areas:

1. A general description of CT technology;
2. the estimated operation and maintenance costs for the Project; and
3. the plan to provide major maintenance on the CT.

[2] Nominal size refers to the general size of the unit. Actual output of a unit depends on a number of factors that vary from unit to unit and site to site.

Q6. HAVE YOU PREVIOUSLY TESTIFIED IN A REGULATORY PROCEEDING?

A. Yes. I submitted an affidavit in Louisiana Public Service Commission, Docket No. U-32759 and U-33770.

II. GENERAL OVERVIEW OF THE PROJECT CCGT TECHNOLOGY

Q7. PLEASE PROVIDE A GENERAL DESCRIPTION OF NOPS.

A. Company witness Jonathan E. Long discusses the Project in more detail, but generally speaking, NOPS will be a modern, advanced CT electric generating unit. The Project will have a nominal size of 226 MW, at summer conditions, with actual output varying based on site-specific conditions and other factors.

Q8. PLEASE DESCRIBE CT TECHNOLOGY.

A. A CT power plant is comprised of a CT that uses a mixture of air and fuel for combustion to drive a turbine that is coupled to an electric generator to produce electricity. A CT is similar to an aircraft jet engine. The turbine consists of an axial compressor that pressurizes ambient air to a pressure of approximately 300-400 pounds per square inch. The air is then mixed with fuel and combusted in a chamber that exhausts into a turbine section that provides the force to turn the common shaft of the compressor, turbine, and electrical generator.

Q9. WOULD YOU EXPLAIN HOW CT TECHNOLOGY DEVELOPED?

A. Yes. The jet engine technology evolved in the 1950s and was later applied to electrical power generation. In the evolution of this technology, the equipment manufacturers have advanced the design to larger, more fuel-efficient models that are referred to as "large frame advanced combustion turbines." The Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC combustion turbine generator, which has been selected for NOPS, was first placed into operation in a Mitsubishi–owned power station in 2009. As of February 2016, there are seven MHPSA 501 GAC combustion turbine generator units in commercial service worldwide with approximately 61,678 operating hours. Also, of that total, 22,281 of those operating hours occurred in the United States by units operated by Dominion Power, Inc.

III. <u>ESTIMATED NON-FUEL O&M COSTS</u>

Q10. HAS THE COMPANY PREPARED AN ESTIMATE OF OPERATIONS AND MAINTENANCE ("O&M") COSTS THAT WILL BE INCURRED IN OPERATING NOPS?

A. Yes. ENO has prepared an estimate, and has provided that to Company witness Orlando Todd for use in estimating the first-year non-fuel revenue requirement associated with the NOPS, based on the current best understanding of what equipment will be installed at the site, and based on a number of other assumptions related to operating systems and conditions at the unit beginning in 2019. The estimate also makes assumptions on a general inflation rate, a payroll escalation rate, and a materials and supplies escalation rate across the estimate time frame for the purposes of presenting the estimate in 2019 dollars. In estimating the O&M expense, the average general inflation rate is assumed to be 2-3% per year, with payroll increasing by 2-4% per year. All cost estimates are based on 2014-2016 estimates, escalated to 2019 by the appropriate escalation rate, escalated each year thereafter by the appropriate escalation rate.

Q11. HOW WAS THE ESTIMATE DEVELOPED?

A. The estimate was developed using a process that was created based on experience gained in the operation of other EOC-operated simple-cycle facilities and information gleaned from general industry sources.

Q12. WHAT IS THE CURRENT ESTIMATE OF O&M EXPENSES?

A. The estimated O&M expenses for NOPS in its first year of operation are contained in Table 1. The O&M numbers in Table 1 are for the O&M associated with NOPS only, excluding any current O&M costs that are otherwise reflected in the Company's rates and CT major maintenance costs expected to be incurred under the long-term service agreement ("LTSA"), which I discuss later in my testimony. My estimate reflects costs in 2019 dollars.

Table 1 **Estimated St. Charles Power Station O&M Expenses (000's)**	
COST BASIS	**TOTAL**
Fixed O&M	
Fixed LTSA (Recovered through Fuel)	-
Fixed Maintenance	**247,682**
Property Tax	-
Variable O&M	
LTSA (Recovered through Fuel)	**4,113,363**
Variable Maintenance	**430,962**
Variable Supplies	-
Baseline	
Fixed Baseline	**715,662**
Variable Baseline	**222,928**
Payroll	
Payroll Fixed	**1,376,344**
Payroll Variable	**215,088**
Total (LTSA included)	
Fixed O&M	**2,339,688**
Variable O&M	**4,982,342**
Total (LTSA excluded)	
Fixed O&M	**2,339,688**
Variable O&M	**868,979**

Q13. HOW WAS THE LABOR COST ESTIMATE PREPARED?

A. A preliminary incremental plant staffing organizational chart was developed, based on the EOCs' experience with CT plant operations in general, that takes into account the expected staffing of the NOPS when it reaches commercial operation. That preliminary organizational chart is attached as HSPM Exhibit RAB-1. Labor rates were then applied to the roughly four different job families and incremental headcount included in that organizational chart. Those costs were then totaled to arrive at the annual plant staff labor figure shown in the table above.

Q14. PLEASE DESCRIBE THE PAYROLL EXPENSE REFLECTED IN TABLE 1.

A. This reflects the payroll associated with incremental headcount required to operate the NOPS, as determined in the staffing model included in HSPM Exhibit RAB-1.

Q15. WHAT TYPES OF COSTS ARE INCLUDED IN O&M BASELINE EXPENSE?

A. NOPS will be a set of large, complex mechanical systems that will require annual maintenance to ensure continued reliable, safe, and economic operations. This maintenance will require materials, chemicals, labor, and rental equipment, and will address the O&M costs for activities not covered by the unit's LTSA for the following equipment and systems: turbine and generators, the plant's electrical instruments and controls, environmental systems, and substation and transmission facilities.

Q16. HOW DOES THE COMPANY INTEND TO MANAGE LONG-TERM MAJOR MAINTENANCE ASSOCIATED WITH NOPS?

A. ENO will enter into a LTSA for maintenance of NOPS with the original equipment manufacturer ("OEM"). ENO has not yet executed the LTSA, but has entered into an LTSA Term Sheet with the OEM, MHPSA, which will serve as the basis for the negotiation of price, major scope terms and limited terms and conditions. Under the terms and pricing outlined in the LTSA Term Sheet, MHPSA will provide major maintenance and services for the MHPSA 501 GAC CT. The purpose of the LTSA is to assure reliability, minimize outage duration, maximize outage intervals and minimize the possibility of unplanned maintenance events. In general terms, MHPSA's scope under the LTSA Term Sheet includes:

- Planned Maintenance
- Unplanned Maintenance, subject to certain cost ceilings
- Remote monitoring and diagnostics services
- Combustion system tuning services
- Provision of an on-site technical advisor

The terms of the Term Sheet and subsequent LTSAs will require MHPSA to maintain the reliability, output and efficiency, NOx and CO emissions, and turbine vibration for the CT and limit the duration of scheduled outages at pre-determined levels.

Q17. WHEN DO YOU EXPECT TO FINALIZE THE LTSA?

A. There is no set timetable, but I would expect the LTSA to be finalized by the end of 2017. I would note that the Company will not incur any costs under the LTSA until NOPS enters commercial operation, which is expected in October 2019.

Q18. PLEASE DESCRIBE THE EXPECTED SCOPE AND PRICING STRUCTURE OF THE LTSA.

A. The LTSA will have a well-defined scope of work for major maintenance activities of the CT, with the scope of covered maintenance being similar to other LTSAs to which the Company is a party. It is also expected that the LTSA will specify a variable payment for such services, which would be determined based on a combination of the number of starts and the operating hours of the facility. Thus, the LTSA costs will be similar to fuel costs in that they are correlated with production and will be incurred only when the NOPS is actually operating. The LTSA may identify other work that the Company may request the OEM to perform, *e.g.*, for extra work or unplanned maintenance above a cap, but the fees for any such work would be negotiated and agreed to in a separate work order.

The term of the LTSA will be for approximately 4,000 equivalent starts on the CT and shall cover maintenance through its second Major Inspection outage. Thus, the term of the LTSA is expected to be approximately twelve to fourteen years in length depending on the actual operational dispatch of the unit over the term of the contract.

Q19. WHAT IS THE ESTIMATED COST OF THE LTSA?

A. As indicated, ENO has not yet executed an LTSA for NOPS. However, for planning purposes only, ENO estimates that LTSA costs for major maintenance work scope will average $[redacted] per year without escalation. If the LTSA were to remain in effect for the full contract term, the expected term cost (in nominal dollars) for the NOPS would be approximately $[redacted], without escalation.

Q20. ARE THE ESTIMATED VARIABLE LTSA COSTS INCLUDED IN THE FIXED O&M COST ESTIMATE YOU DESCRIBED EARLIER?

A. No. The expected costs for major maintenance under the MHPSA LTSA, *i.e.* fees for which will vary depending on production from the unit, are not included in the fixed O&M cost estimate.

Q21. WHAT ARE THE BENEFITS OF THE LTSA VERSUS THE COMPANY PERFORMING LONG-TERM MAJOR MAINTENANCE?

A. As with other LTSAs entered into, the MHPSA LTSA is expected to provide lower maintenance costs, better availability of spare parts, guaranteed performance of unit reliability, guaranteed maintenance response times, and specified coverage for a certain amount of unplanned maintenance.

Q22. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes.

AFFIDAVIT

STATE OF TEXAS

COUNTY OF Montgomery

NOW BEFORE ME, the undersigned authority, personally came and appeared, **ROBERT A. BREEDLOVE**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Robert A. Breedlove

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 10 DAY OF JUNE, 2016

NOTARY PUBLIC

My commission expires: Jan 27, 2019

TARA SCHWEGLER
Notary Public, State of Texas
My Commission Expires
January 27, 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-________**

EXHIBIT RAB-1

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JUNE 2016